Canadian Utilities Limited
Annual Report 1994

An ATCO Company

CORPORATE MISSION

Canadian Utilities is an investor-owned Alberta-based company, committed to achieving above average earnings and dividend growth through a balance of its core utility operations and diversified but complementary business. The Company is dedicated to being a leader in the optimization of human, technological and financial resources while maintaining its reputation for integrity and quality of service.

Contents

COVER: Block 2 steam turbine installed at the 1,000-megawatt Barking Power Station near London, England, which is nearing completion after less than three years of construction. CU Power International Limited (CUPIL) has a major interest in the new plant, is responsible for managing the construction and commissioning phases, and has a 15-year contract to operate the station.

FINANCIAL HIGHLIGHTS

		1994		1993	Change
FINANCIAL *(millions)*					%
Revenues					
Natural gas utility	$	**887.9**	$	772.1	15.0
Electric utility		**650.2**		602.3	8.0
Other		**38.2**		11.9	221.0
Total	$	**1,576.3**	$	1,386.3	13.7
Earnings attributable to Class A non-voting and Class B common shares	$	**138.2**	$	128.8	7.3
Cash provided from operations	$	**257.6**	$	267.6	(3.7)
Capital expenditures	$	**215.1**	$	259.3	(17.0)
CLASS A NON-VOTING AND CLASS B COMMON SHARE DATA					
Earnings per share	$	**2.22**	$	2.07	7.3
Dividends per share					
— annual	$	**1.44**	$	1.42	1.4
— quarterly	$	**0.36**	$	0.355	1.4
Dividend payout ratio	%	**64.7**	%	68.5	(3.8)
Equity per share	$	**16.62**	$	15.83	5.0
Return on equity	%	**13.7**	%	13.4	0.3
Market price range					
— Class A non-voting	$	**27-$21⅞**		$26⅞-$20¼	
— Class B common		**$27⅜-$23⅛**		$26⅞-$20⅜	
UTILITY OPERATIONS					
Electric retail sales (millions of kWh)		**8,595**		8,035	7.0
Natural gas system throughput (petajoules)		**578**		541	6.8
Electric customers at year-end		**174,041**		171,130	1.7
Natural gas customers at year-end		**713,450**		698,519	2.1

LETTER TO THE SHAREHOLDERS

In 1994, Canadian Utilities achieved its fifth consecutive year of earnings increases and introduced operating improvements which resulted in lower costs and better service.

R. D. Southern and J. D. Wood

For the year ended December 31, 1994, earnings attributable to Class A and Class B shares were $138.2 million ($2.22 per share) compared to $128.8 million ($2.07 per share) in 1993. The 7.3% increase in earnings in 1994 continued CU's record of strong annual earnings growth.

While electric and natural gas utilities continue to be the mainstay of the Corporation's business, shareholders are beginning to benefit from earnings on complementary operations. Highlights included the first significant earnings from independent power plants (IPP), the expansion of natural gas complementary operations, and new joint venture contracts for Frontec in Northern Canada and Alaska.

Major factors that caused the earnings increase were higher electric retail sales to the oilfield, oilsands, forestry and chemical sectors, as well as increased commercial, residential and rural sales; higher natural gas sales and gas transportation and storage revenues; lower financing costs; revenues from the McMahon Co-generation Plant and the Edmonton Ethane Extraction Plant; and colder weather. These positive factors were partially offset by increased operating expenses.

Utilities

Investor-owned utilities in Canada and elsewhere are facing a business environment of greater competition as well as growing expectations from customers and regulatory authorities. CU's electric and natural gas utilities have met these challenges by simultaneously reducing costs and improving service. Customers-per-employee and sales-per-employee ratios have increased steadily over the last decade (see charts at right). This improvement will continue in the years ahead.

Beyond productivity improvements, the growth of our utility subsidiaries is largely a reflection of economic development in Alberta, where more than 95% of our customers live and work.

Alberta's economic growth has outperformed other provinces over the past two years. During 1994, strong performance by the oil and gas, forestry and manufacturing industries more than offset the economic effects of the substantial spending cuts by the provincial government.

Because many of the province's manufacturing industries are energy intensive, both electric and natural gas utilities benefit from increased manufacturing output. The chemical and pulp and paper sectors in particular had a good year in 1994, which encouraged the acceleration of expansion plans.

In 1994, CU's utility customers totalled 887,491— 2% higher than the previous year. The growth of Northwestern Utilities and Canadian Western Natural Gas was reflected in a 7% increase in natural gas throughput to 577.5 petajoules. Alberta Power's electric retail sales grew 5.5% during the year. Including consolidated sales of subsidiaries in the Yukon and Northwest Territories, total electric retail sales in 1994 were 8,595 million kilowatt hours, compared to 8,035 million kilowatt hours in 1993.

In October, the Alberta government announced proposed changes to the electric utility industry in Alberta. Of particular importance to Alberta Power is that transmission costs and the cost of Alberta's existing generating facilities will continue to be averaged across the province. This means that all Albertans continue to share equally in the low cost of existing generation and benefit from an integrated transmission system. The cost of future generating facilities will not be averaged. In the longer-term, as new generating capacity is required, prices paid by Alberta customers may vary depending on which utility supplies their electricity.

... the first significant earnings from IPP, expansion of natural gas complementary business and new joint venture contracts for Frontec.

The federal government budget on February 27, 1995 announced the elimination of the Public Utilities Income Tax Transfer Act (PUITTA), which provides federal income tax rebates to customers of investor-owned electric and natural gas utilities. PUITTA puts customers of investor-owned utilities on an equal footing with customers of government-owned utilities which do not pay income taxes. The loss of PUITTA would not affect CU's earnings, but we are concerned about the impact on customer bills and on the economy of our service areas. CU companies are consulting with regulatory authorities to lessen the impact on customers, and appealing for reinstatement of the rebates in the interest of fairness to our customers.

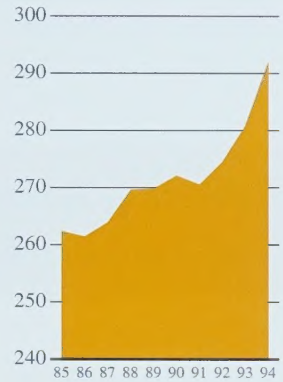
Complementary Operations

Effective January 1, 1995, Frontec became a wholly-owned subsidiary of Canadian Utilities. CU purchased ATCO Ltd.'s 50% interest in Frontec as well as ATCO's property management operations. The latter are now conducted by Frontec Services Limited.

Since its inception in 1986, Frontec has established itself as the leading Canadian contractor of technical services. The company now manages more than $3 billion in client-owned assets and facilities.

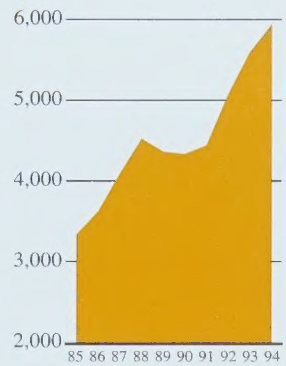
Productivity

Natural Gas Customers Per Employee



Productivity

Alberta Power Electric Retail Sales Per Employee
(megawatt hours)



Frontec achieved a major breakthrough in 1994 in receiving, in a joint venture with a native-owned Alaska company, the contract to operate and maintain the Alaska Radar System. In December, the company was awarded a contract to continue operating and maintaining Canada's North Warning System in a joint venture with a Northern native-owned company. Both contracts reflect Frontec's successful performance of the North Warning System contract since 1988 and its ability to adapt to changing government requirements.

CU's complementary business strategy is beginning to be significantly reflected in earnings, as the McMahon Co-generation Plant at Taylor, B.C. completed its first full year of operation.

Barking Power Project continued within budget and on schedule.

During 1994, construction of the 1,000-megawatt Barking Power Project in England continued within budget and on schedule to begin commercial operation in the second quarter of 1995. CU Power International Limited (CUPIL) is responsible for managing the construction and commissioning phases and has a 15-year contract to operate the station.

In addition to the U.K., CUPIL is actively pursuing IPP in Western Europe, Australia and North America.

In January, 1995, Mid-West Gas Transmission Ltd. and the Wabamun-Hinton North Canadian Oils Limited gas transmission line were purchased from Norcen Energy Resources Limited. The acquisition establishes CU Gas Limited as a major gas processor in Alberta, complementing earlier investments in gas gathering and processing and the purchase of a one-third interest in the Edmonton Ethane Extraction Plant.

Financial

During the year, CU was able to take advantage of lower interest rates to reduce financing costs. The company redeemed $191.1 million of preferred shares with dividend rates ranging from 7.08% to 8.74% and issued $200.0 million of preferred shares with dividend rates of 5.30% and 6.60%. Also, $148.2 million of long-term debt with interest rates ranging from 10.40% to 17.5% was refinanced at lower rates of interest ranging from 8.73% to 8.95%.

In January, 1995, the Board of Directors declared a first quarter dividend of 36.5 cents per share payable March 1 to shareholders of record on February 10. This is the 23rd consecutive year in which CU's common share dividend has increased.

General

In May, the Board of Directors welcomed the Rt. Hon. D. F. Mazankowski, P.C., D.Eng., L.L.D. to the Board.

The Board extends its appreciation to N. W. Robertson, who retired in 1994 after serving as a Director since 1980.

With much sadness, we report the passing on January 27, 1995 of Wilmat Tennyson, a Director since 1990 (see page 59 of this report).

The Board extends its appreciation to J. H. Cook, who retired as Assistant Corporate Secretary after many years of distinguished service to the corporation. D. R. Cawsey was appointed to succeed Mr. Cook.

Effective January 1, 1995, the following appointments were made in the Office of the Chairman — ATCO Ltd. and Canadian Utilities Limited: C. O. Twa was appointed Executive Vice President; M. M. Shaw was appointed Vice President, and S. R. Werth was appointed Vice President, Administration.

Achieving better service with fewer resources is only possible through a commitment to excellence throughout the corporation. Sincere congratulations go to directors, officers and employees for meeting their goals again in 1994. The continuing support of shareholders and customers is greatly appreciated.

On behalf of the Board of Directors,

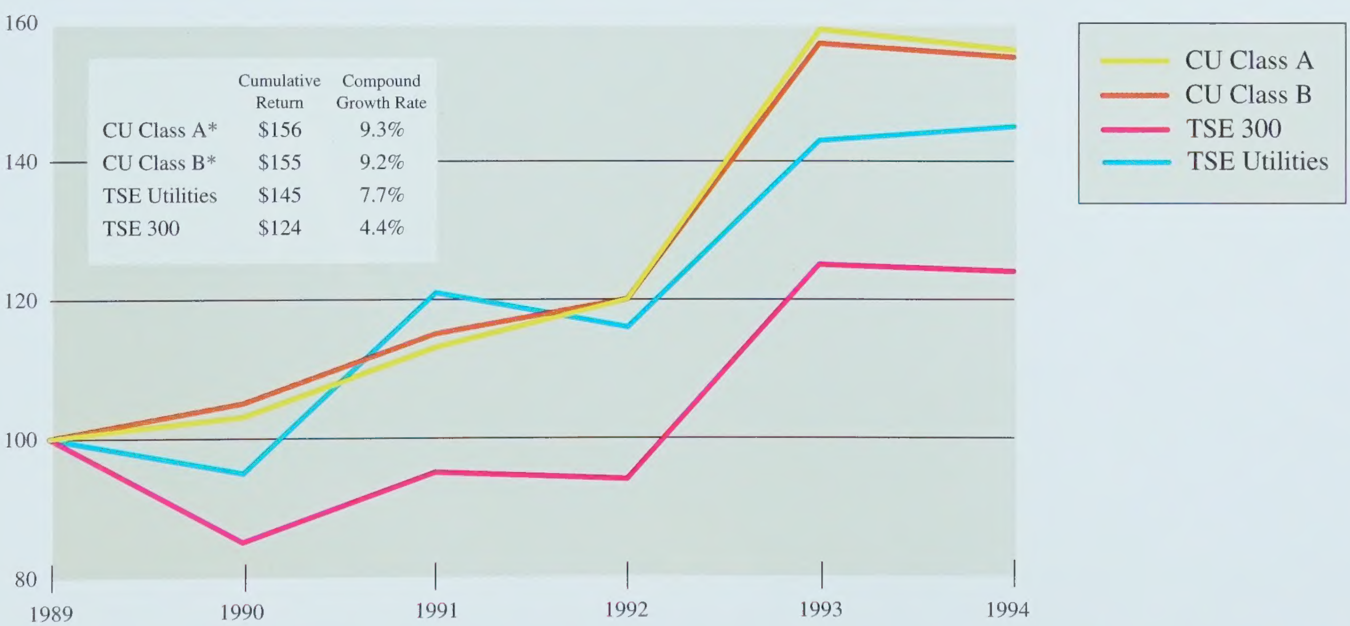
R. D. Southern
Chairman of the Board and Chief Executive Officer

J. D. Wood
President and Chief Executive Officer

March 8, 1995

FIVE-YEAR TOTAL RETURN ON $100 INVESTMENT

The graph below compares the cumulative shareholder return over the last five years on the Class A non-voting shares and Class B common shares of the Corporation (assuming a $100 investment was made on December 31, 1989) with the cumulative total return of the TSE 300 Composite Index and the TSE Utilities Subindex, assuming reinvestment of dividends.



*Note that the calculation of CU shareholder returns since 1990 includes the distribution to shareholders of shares of ATCOR Resources Ltd., effective November 23, 1990, on the basis of one ATCOR share for every four CU shares held. The calculation assumes the continued holding by shareholders of these ATCOR shares.

Natural Gas Utility Operations

- Canadian Western Natural Gas Company Limited
- Northwestern Utilities Limited

The Corporation's natural gas utility operations are conducted by two subsidiaries. Canadian Western Natural Gas Company Limited serves southern Alberta, including Calgary, Lethbridge and Airdrie; and Northwestern Utilities Limited serves north-central Alberta, including Edmonton, Camrose, Fort McMurray, Fort Saskatchewan, Grande Prairie, Lloydminster, Red Deer, St. Albert, Spruce Grove and Wetaskiwin.

Growth in 1994 of 14,931 natural gas customers. Gas throughput increased by 37 petajoules.

At the beginning of 1995 Northwestern acquired the Wabamun-Hinton and Edmonton-Bittern Lake gas transmission lines. In making the acquisition, Northwestern obtained operating and financial control over lines that are integral to Northwestern's market area.

System Throughput

Canadian Western's customer base increased 2.6% in 1994, and Northwestern's increased 1.7%. At year-end, Canadian Western served 340,914 customers in 115 communities and Northwestern served 372,541 customers in 175 communities.

Natural Gas Sales and Transportation (Terajoules)

	Sales	Transportation	Total
Industrial	12,251	175,881	188,132
Commercial	93,715		93,715
Residential	98,008		98,008
Other	6,925	126,367	133,292
Affiliates	361	63,992	64,353
Total System Throughput	**211,260**	**366,240**	**577,500**

Total system throughput was 577.5 petajoules (PJ), an increase of 6.8% over 1993. The two major reasons for growth in throughput were increased transportation service for industrial

Extending natural gas service to a new housing development near Canmore.

Innovative ground-thawing device developed by Canadian Western.

Urban main replacement program continued in 1994.

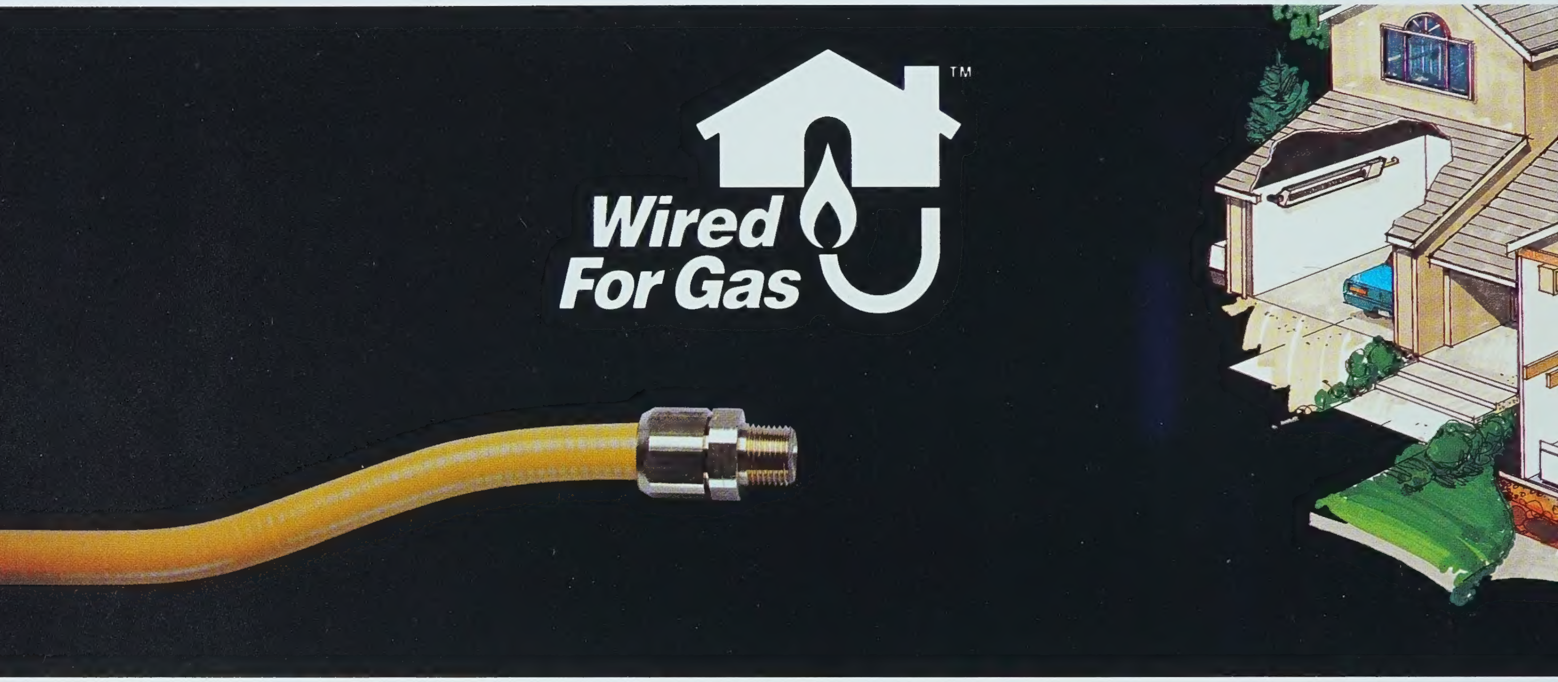
Natural gas-fueled bus serves an Edmonton seniors' complex.

customers and the gas producing sector, and colder weather. Temperatures were 3.2% colder than the previous year, and 2.3% colder than normal.

Capital Expenditures

Capital expenditures to provide for customer growth and to meet existing customers' needs totaled $114.9 million. The largest individual project in 1994 involved $15.9 million spent to replace bare steel pipe originally installed in urban areas in the 1920's and 1930's. Both companies have 10-year bare mains replacement programs, with Canadian Western in its fourth year and Northwestern in its eighth year.

At year end, the book value of property, plant and equipment, net of accumulated depreciation, was $1.2 billion.



Gas Supply

Record drilling activity, triggered by higher natural gas prices in the early part of the year, produced an oversupply of natural gas in Alberta. This oversupply, in combination with increased storage capability within the province and milder weather in November and December, led to significant price declines. In December, short-term gas sold for under $1 per gigajoule, less than half the price 12 months earlier.

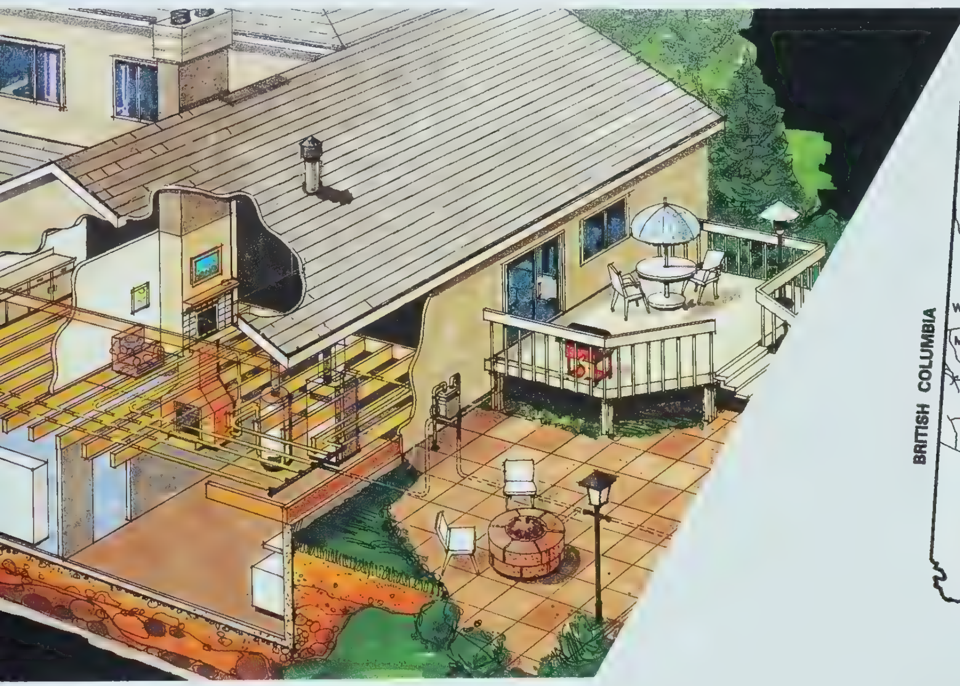
Storage

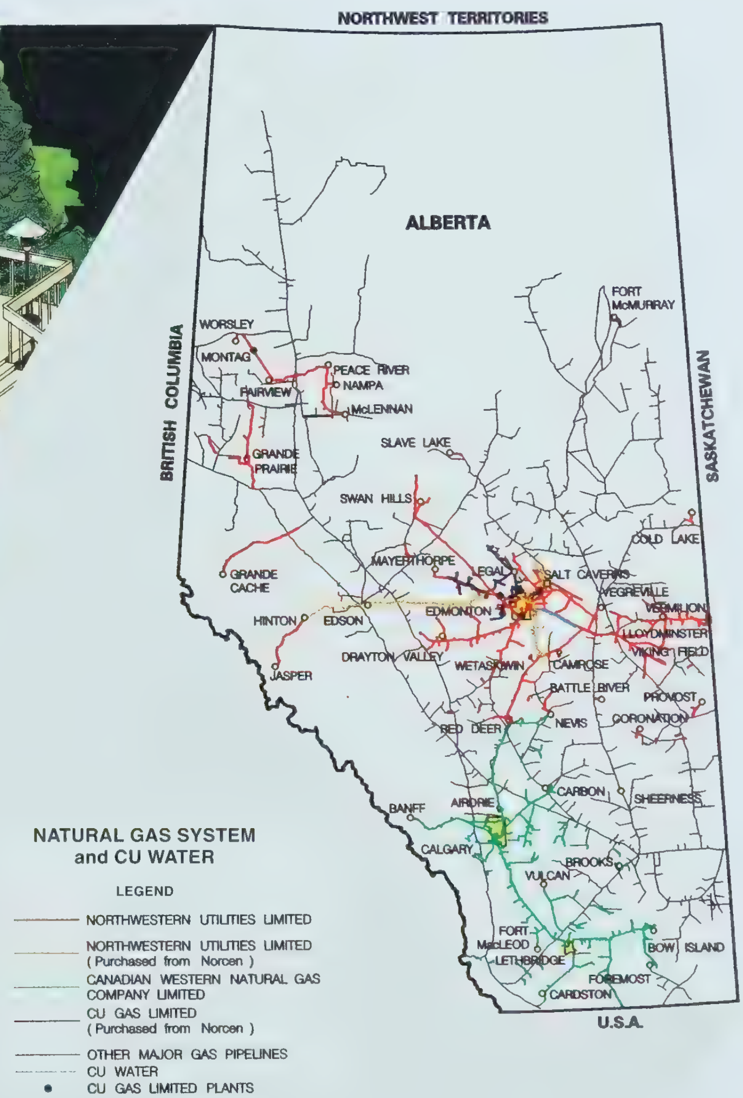
Northwestern brought a sixth salt cavern into service at its Fort Saskatchewan gas storage facility in time for the 1994/95 winter season. The increased storage capacity ensures a secure supply for Northwestern's sales and transportation customers during extremely cold weather.

Regulation

The Alberta Public Utilities Board (PUB) approved regular changes to the gas cost recovery of both companies on April 1 and November 1. Since the cost of gas is a flow-through cost, the two utility companies receive no earnings benefit from changes in the gas cost recovery rate. Our customers received the full benefit of the price reductions.

During the year the industry worked with the Government of Alberta to draft the regulations surrounding Bill 51, the Gas Utilities Statutes Amendment Act. This legislation, scheduled to become law in 1995, will provide the framework to allow residential, commercial and institutional customers to purchase their gas supply directly from producers, subject to certain conditions. The legislation may prompt some core market customers to switch from sales to transportation service, but this will affect neither total throughput nor earnings.





Construction of Northwestern's new gate station to serve the City of Lloydminster.

Marketing

The companies continued to promote natural gas as a vehicle fuel (NGV). During the year they participated in demonstrations of full-size NGV city buses in Calgary and Edmonton, and facilitated the purchase of NGV shuttle buses for the transit systems of both cities. Subsequently, the City of Edmonton received an environmental award from the Canadian Gas Association in recognition of its environmental consciousness and use of natural gas vehicles.

During the year, Canadian Western launched its "Wired For Gas" program to increase the penetration of natural gas-fueled appliance sales to new and renovated homes. The program promotes the advantages of new flexible natural gas piping for houses, and highlights the recently-approved "quick connect" system which makes it possible to plug in gas appliances as easily as electric ones.

– Health and Safety Plan
– Environmental Boards of Management
– Service Improvement Teams

Franchises

Franchise agreements with 16 communities were successfully re-negotiated in 1994.

Health and Safety

In 1994 the companies approved and began to execute a five-year health and safety plan. The plan emphasizes the involvement of employees in the development and continuing assessment of safe work practices. Key components of the plan include: hazard assessment, safe work practices, training, accident investigation, contractor safety, emergency preparedness and occupational health and safety program control.

The companies have a long-standing substance abuse policy which relies on supervision and testing for reasonable cause, and provides for rehabilitation. With increased focus on liability and concern for public safety, the companies intend to develop a program in 1995 which would introduce testing for substance abuse for safety-sensitive job positions.

Environment

The continuing commitment of Northwestern and Canadian Western to the protection of the environment was demonstrated in 1994 by the introduction of Environmental Boards of Management in each company. During the year, the Boards of Management issued environmental policy and procedures manuals as part of three-part environmental action plans. Coordinated between the companies, the plans are expected to be fully implemented by the end of 1995.

Service Training

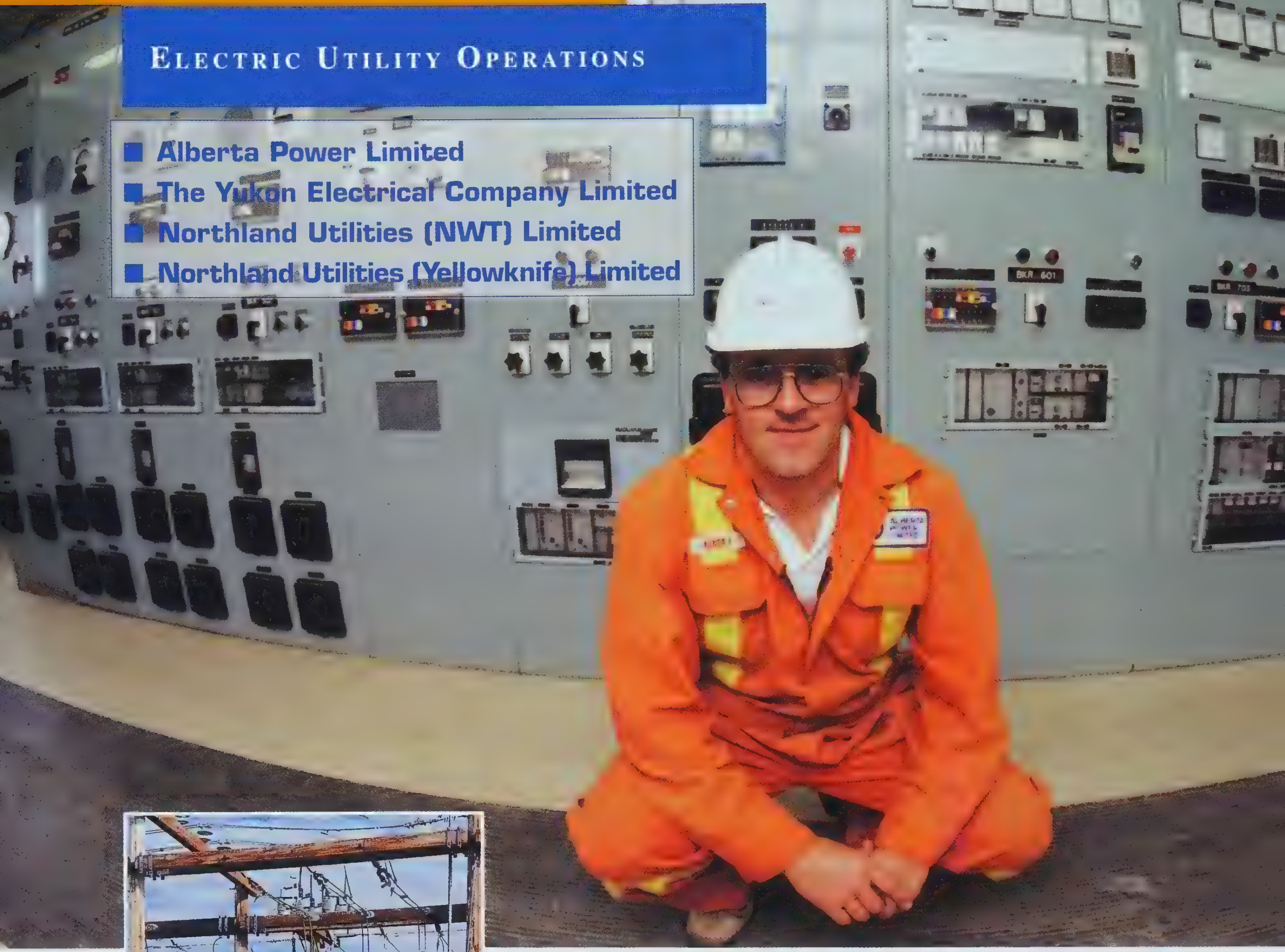
Building upon their customer service achievements of 1992 and 1993, the companies created service improvement teams for urban service line installation and for customer billing, and provided continuing training to enable employees to achieve excellence in customer relations.

A seismic survey was conducted to determine the best drilling location for the expansion of the Carbon storage facility east of Calgary. Here, cables are being dropped by helicopter on the seismic line near Canadian Western's Carbon plant.


Canadian

ELECTRIC UTILITY OPERATIONS

- Alberta Power Limited
- The Yukon Electrical Company Limited
- Northland Utilities (NWT) Limited
- Northland Utilities (Yellowknife) Limited



Equipment used to transmit meter reads over high voltage lines.

With automatic meter reading equipment at the Three Hills Substation.

Canadian Utilities serves electric customers through four operating companies: Alberta Power Limited; its subsidiary, The Yukon Electrical Company Limited; Northland Utilities (NWT) Limited; and Northland Utilities (Yellowknife) Limited.

During 1994, sales by all electrical operations increased by 7% to a total of 8,595 million kilowatt hours. Of this increase, 1.5% was the result of including 12 months of energy sales by Northland Utilities (NWT) and Northland Utilities (Yellowknife). Only three months of sales were included in 1993 year-end results due to the ownership structure of Northland Utilities Enterprises Ltd. (NUE). Effective October 1, 1993, the company increased its interest in NUE and from that date has consolidated the accounts of NUE in the company's financial statements.

Growth was driven mainly by increased sales to Alberta Power's industrial customers.

A total of 2,911 customers were added to electric utility operations in 1994, bringing total customers served to 174,041. The Alberta and Yukon operations together added 2,523 customers, while the Northwest Territories operations grew by 388 customers.

Retail Electric Sales
(Alberta, Yukon and Northwest Territories)

	Millions of Kilowatt Hours	% of Total
Industrial	5,886	68.5
Commercial	1,382	16.1
Residential	847	9.9
Company Rural	248	2.9
REAs*	202	2.3
Other	30	0.3
Total	**8,595**	**100.0**

*Rural Electrification Associations

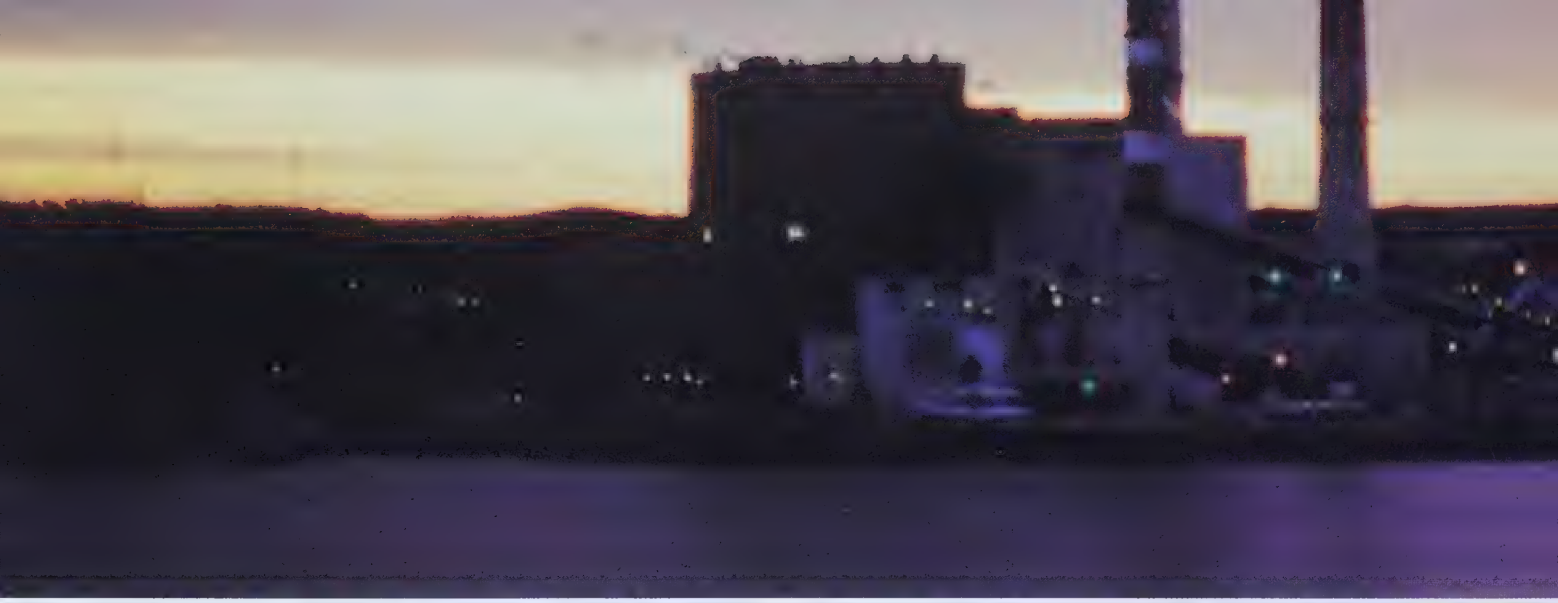
Alberta Operations

Alberta Power serves 329 communities in east-central and northern Alberta, as well as two communities in Saskatchewan. This service territory covers approximately 62% of Alberta and includes much of the province's natural resource development area. Customers include the petroleum and forestry industries, farms, small to mid-sized cities and isolated northern communities.

Improved Alberta economy and increased oilfield activity helped boost electric sales.

More than 70% of Alberta Power's electric sales are to industrial customers. A large proportion of these are in the oil and gas sector, including major oilsands developments near Fort McMurray. An improved Alberta economy and increased oilfield activity were the primary factors that helped boost the company's industrial sales in 1994. The forest products sector — predominantly in the Slave Lake area — and the chemical sector also used more electricity than previously. Alberta Power's energy sales growth of about 5.5% during 1994 was more than twice the growth that was forecast at the beginning of the year.

In October, the provincial government announced proposed changes to the structure of the electric industry. Alberta Power played an active role in the discussions leading up to this announcement, along with other industry, consumer and environmental groups. The new structure will feature changes such as competitive bidding for new power plants, and will allow for incentives to encourage utilities to keep costs down.



Battle River station at dusk.

The cost of Alberta's existing generating stations — which provide power at an average cost that is significantly lower than new generating units could deliver — will continue to be shared across the province.

The new structure continues to average all transmission costs across the province. Averaging the costs of transmission and existing generation means Alberta Power's customers will continue to pay electric rates very similar to those paid elsewhere in the province. This means the company and its customers remain competitive. The changes scheduled to take effect on January 1, 1996 do not include retail wheeling (an arrangement whereby customers can bypass their local utility to purchase power from an alternate supplier). Participants have agreed to study an option that would allow customers to make their own arrangements for additional generation they need to meet future load.

... reducing costs per kWh and improving customer satisfaction, safety and environmental protection.

Strengthening Operations

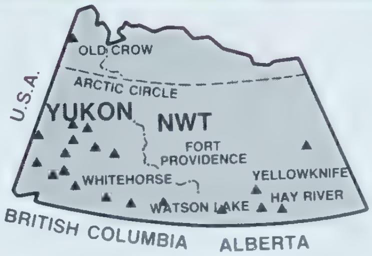
To meet the challenges of the new business environment and the needs of its diverse service area, Alberta Power is focusing on building a better company in four priority areas: reducing costs per kilowatt hour, and improving performance in the areas of customer satisfaction, safety, and environmental protection. Some examples include:

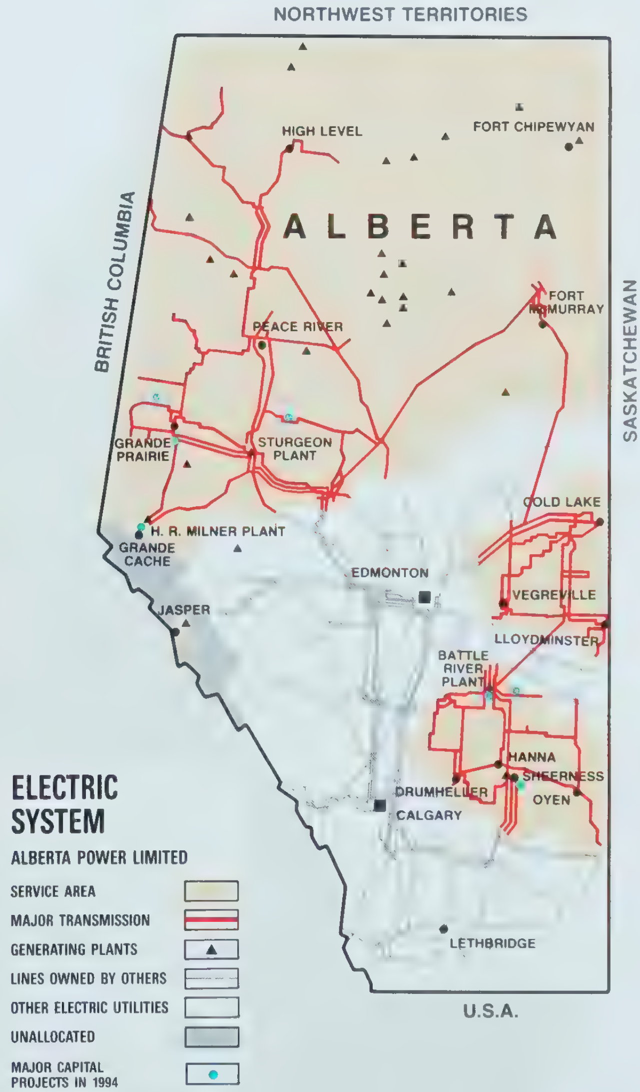
- Alberta Power's product delivery process is being re-designed to dramatically reduce connect time and attract more sales.
- We are introducing a new industrial rates package which offers customers more price options.
- Development of a new customer information system continues. The industrial portion of the new customer information system is scheduled to be completed by the end of 1996, with residential and commercial components to follow. The new system will ensure front-line staff can respond quickly to customer billing and information needs.

Checking main power feed to Renaissance gas plant at Forestburg.

- Through the Jasper Energy Efficiency Project, which Alberta Power launched in 1992 and completed in August, 1994, the community of Jasper reduced its peak electric demand by 2,100 kW — approximately 20%. In addition, carbon dioxide emissions were reduced by 3,128 tonnes per year, and nitrogen oxides by 6.6 tonnes per year, at the company's Palisades Generating Station in Jasper National Park.
- Worker health and safety is being enhanced through new training programs, safe-work planning and hazard assessment procedures.
- Corporate environmental management programs are being enhanced. For example, Alberta Power's environmental auditing program, initiated in 1988, is now being extended to all of its facilities on a five-year cycle, including small generating plants, service centres, microwave stations, substations, and transmission and distribution lines.

Installing a new POWER**PLUS**™ *meter.*





- In other environmental initiatives, Alberta Power has formally undertaken a voluntary toxic substance reduction program as part of the national effort known as the ARET (Accelerated Reduction/Elimination of Toxics) challenge. The first step involved identifying materials used by the company that are on a list of toxic compounds identified by ARET participants. Alberta Power is now identifying options to reduce or eliminate the use of toxics, assess related costs and provide a timeline to achieve significant results by the year 2000.
- In response to the National Action Program on Climate Change, the company has committed to working with federal and provincial ministries and the Canadian Electrical Association to develop voluntary actions that deal with climate change issues. These voluntary actions will focus on internal energy production and utilization improvements and on customer energy management services.
- Customer energy education and safety programs are also being updated and reinforced.

The arrival of the POWER**PLUS**™ automatic meter-reading (AMR) program represents a major customer service improvement for the company. In 1994, 14 substations were equipped with two-way automatic communication system technology to send meter readings over Alberta Power's distribution lines and more than 7,000 AMR meters were installed in the company's service territory. The technology eliminates estimated power bills for customers. AMR will be phased in for all Alberta Power customers over the next eight years.

Other applications of the system also look promising and will bring new revenue opportunities to the company. The new services include: water AMR services for municipalities; natural gas AMR service for natural gas distributors serving communities; as well as alarm notification, remote control, interactive data monitoring and site monitoring of distant operations for industrial customers.

Capital Spending

During 1994, Alberta Power invested $93 million in capital projects to improve and extend service to customers. Project expenditures included, among others:

- $45.1 million spent on distribution projects, including $28.3 million for oilfield extensions, new extensions, and transformers and regulators to meet the needs of an increased number of customers in an improving economy.
- $15.5 million spent on transmission improvements, including a $3.5 million project to increase the capacity of the Paintearth Creek substation near Alliance to meet the growing load from conventional oil and gas activity in east central Alberta.
- work initiated on: a $1.5 million project to supply the Ainsworth Lumber Company Ltd. oriented strand board and finger jointed lumber facility south of Grande Prairie; a $3.7 million project to serve the Conwest Gas Plant and the Valhalla Oil Field northwest of Grande Prairie; and a $3.0 million project to supply the Tolko Industries Ltd.'s oriented strand board facility northwest of High Prairie.

Environmental monitoring at Battle River Station.

- $14.7 million for improvements at Alberta Power's three major generating stations to enhance worker health, safety and productivity, and to improve station reliability, production efficiency and environmental protection.

Yukon Operations

The Yukon Electrical Company Limited, a wholly-owned subsidiary of Alberta Power, serves close to 13,900 customers in the Yukon and B.C. About 1,500 of these customers are in the service area of the Yukon Energy Corporation (YEC) and are not included in consolidated customer totals in this report. Under a management agreement with YEC, however, Yukon Electrical manages $118.4 million in assets owned by YEC, which include generation, transmission and distribution facilities.

In 1994, Yukon Electrical invested approximately $3 million in the electrical system, bringing the company's investment in capital projects in Yukon to approximately $38 million. The majority of capital projects completed during the year related to extensions and upgrades to the distribution system to meet the needs of new customers. The commencement of new mining activity in recent months has dramatically improved the outlook for the Yukon economy, which has been depressed for the last two years.

Northwest Territories Operations

The Northwest Territories experienced a significant increase in mining exploration during 1994. Diamond mining exploration contributed to Northland Utilities (Yellowknife) Limited's strongest construction year on record. The company also experienced one of its best safety records ever. Meanwhile, Northland Utilities (NWT) Limited is setting new peak demand records in the remote communities it serves.

Together, the two operations added 388 customers in 1994, an increase of 5% over the previous year. Northland Utilities (Yellowknife) was serving 6,120 customers at year end in Yellowknife, while Northland Utilities (NWT) was serving a total of 2,318 customers in the town of Hay River and seven other communities in the Northwest Territories.

Yukon Electrical maintenance.

Complementary Operations

- CU Power International Limited
- CU Gas Limited & CU Water Limited
- Frontec
- ATCOR Resources Ltd.

CU Power International Limited

Significant opportunities for independent power developers are emerging in Canada and around the world as governments embrace deregulation and encourage competition in the electric utility industry. Meeting the energy needs of industrial customers through co-generation presents an additional window of opportunity for CU.

CU Power International Limited (CUPIL) was established to participate in this changing marketplace and maximize CU's considerable expertise as a developer and operator of electric utility systems.

Barking Power Station comes on stream in second quarter of 1995.

The company's expertise extends to project management, construction and operation of co-generation and combined-cycle power stations as well as the construction and operation of electric transmission systems.

Barking Power Project

Construction of a 1,000-megawatt, $1.4 billion, natural gas-fired, combined-cycle generating plant at Barking in London, England, continued on schedule and on budget.

Synchronization of the first two turbines was achieved in December, 1994. Commercial operations of the first block (400 megawatts) are scheduled to begin in April, 1995. The second block (600 megawatts) will come on stream in June, 1995.

Thames Power Limited, a company jointly owned by CUPIL's U.K. subsidiary and BICC plc, an international engineering and cable manufacturer, owns 51 percent of the Barking project. CUPIL is responsible for managing the construction and commissioning phases and has signed a 15-year contract to operate the power station.

Left to Right:

Control Room at the Edmonton Ethane Extraction Plant.

Alaska Radar System facility at Tatalina, Alaska.

Working with some of Barking's 850 km of cable in Cable Run Alley of the Control Building.

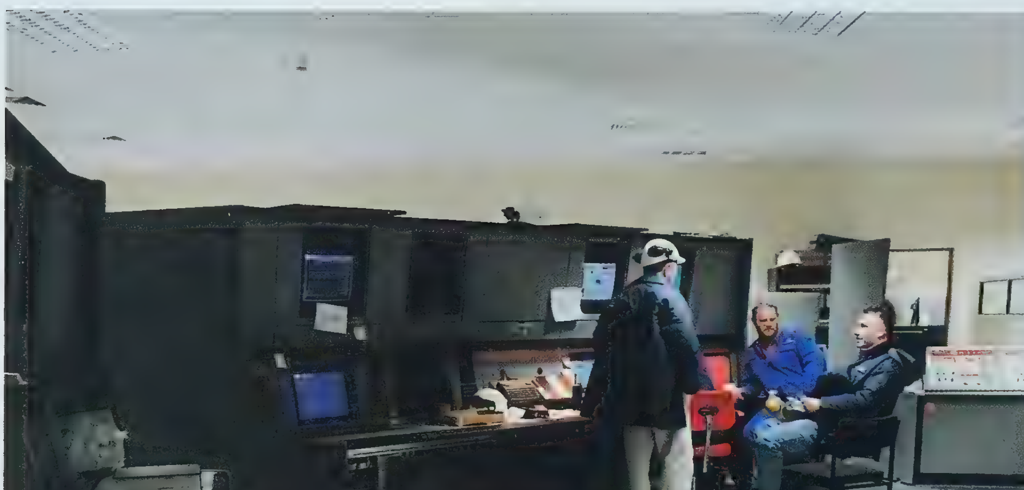
The Fort Saskatchewan liquids extraction plant now owned and operated by CU Gas Limited.

McMahon Co-generation Plant

Electric power sales from CUPIL's first generation project began in November, 1993 under a 20-year agreement with BC Hydro. The McMahon Co-generation Plant in Taylor, British Columbia is a joint venture between CUPIL's subsidiary, CU Power Canada Limited, and Westcoast Power Inc. The plant achieved its availability targets in 1994.

Potential Projects

In 1994, negotiations proceeded with potential partners in North America, England, Europe and Australia concerning the development opportunities which complement its expertise and position the company for continuing growth in key national and international markets.



Barking Station's control room.

Switchyard outside Barking's Mai Turbine Hall.

Inside the Barking Station's main cooling water structure prior to flooding.

CU Gas Limited & CU Water Limited

CU's natural gas-related complementary business activities in 1994 remained focused in the areas of natural gas gathering and processing, development of natural gas storage, water transmission and distribution, and municipal customer billing and account management services.

Gas Gathering and Processing

In January, 1995, CU Gas Limited purchased from Norcen Energy Resources Limited the natural gas gathering and processing assets of Mid-West Gas Transmission Ltd. These assets include an extensive gas gathering system in the Edmonton area, two sour gas processing plants at Carbondale and Golden Spike, a liquids extraction plant at Fort Saskatchewan and associated contracts for gas supply and market. This system is capable of processing 70 million cubic feet per day of natural gas. This acquisition is a significant addition to our gas gathering and processing business in Alberta, complementing earlier investments in gas gathering and processing at Riviere and Montag and the 1993 acquisition of one-third ownership of the Edmonton Ethane Extraction Plant.

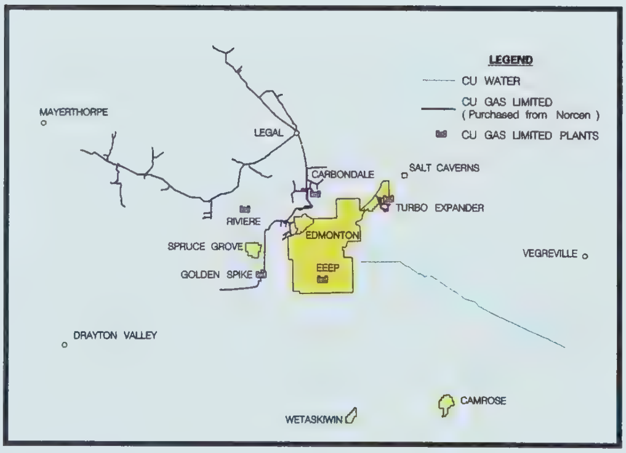
Significant addition to our gas gathering and processing business.

The investment in the Edmonton Ethane Extraction Plant performed well in 1994. CU Gas Limited played a significant role in optimizing plant efficiencies and sustaining high plant throughput of high quality natural gas which will continue in 1995 and beyond.

CU Gas Limited will continue to focus on growth in gas gathering and processing in Alberta.

Gas Storage

In 1994, CU Gas Limited developed an incremental 5 billion cubic feet (Bcf) of natural gas storage at Carbon, Alberta. Long-term contracts were secured with three customers for the majority of this capacity.



CU Gas and CU Water facilities in the Edmonton region.

Water truck filling up at CU Water facility east of Edmonton.

Golden Spike Gas Plant west of Edmonton, recently purchased by CU Gas Limited.

Edmonton Ethane Extraction Plant.

Monitoring equipment at Carbondale Gas Plant.

FRONTEC

Effective January 1, 1995, Frontec became a wholly-owned subsidiary of Canadian Utilities. CU purchased from ATCO Ltd. both its 50% interest in Frontec and its property management operations which Frontec will manage.

Frontec was established in 1986 to serve an emerging market for technical services in Canada. The goal was to build the best technical service business in Canada, and then to market its services worldwide. Today, Frontec is realizing this goal with offices across Canada and in Alaska, and staff which has grown from five to 600.

Frontec is a group of affiliated companies providing management, operation and maintenance and technical services for customers in the defence, transportation and industrial sectors. Frontec provides and manages comprehensive support services for technical systems and system facilities, including:

- operation and maintenance
- systems installation and integration
- logistics and transportation support
- technology transfer and training

Frontec is now 100% owned by Canadian Utilities.

Operation and Maintenance

Frontec has operated and maintained the North Warning System (NWS) radar sites and support facilities since 1988. In 1994, Frontec and its native-owned joint venture partner, Pan Arctic Inuit Logistics Corporation, were awarded a five-year contract to operate and maintain the NWS starting April 1, 1995.

In May, 1994, Frontec and its Alaskan native-owned joint venture partner, Piquniq Management Corporation, were awarded a one-year contract, with four option years, to operate and

SYMBOL	DESCRIPTION
○ (small)	Short Range Radar Site
○ (large)	Long Range Radar Site
□	Long Range Radar Site (Unmanned)

maintain the Alaska Radar System, which is the sister system to the NWS. By year-end, transition from the previous contractor had been completed.

Systems Installation and Integration

Frontec is a member of an international team providing the Department of National Defence with a state-of-the-art command, control and communications system through the Iris project. Frontec's portion of the project, which is now based in Calgary, includes the installation of communications equipment in some 7,000 Canadian Forces vehicles deployed across Canada and at UN peacekeeping locations around the world. Building on its successful implementation of the initial stages of the work, Frontec has submitted a proposal to undertake major additional work on this contract.

Narwhal

Narwhal Arctic Services, Frontec's division in the North, consolidated its operational centre in Yellowknife from its Edmonton and Iqaluit offices. This division undertakes construction and technical services work across the North.

New Opportunities

Frontec will continue to pursue its core business areas in Canada, providing cost-effective solutions for customers in government and private industry. At the same time, it will pursue new customers in Canada and internationally, and design innovative integrated services to satisfy their unique needs.

DND Photo

The Communications System test bed at the North Warning System Support Centre, North Bay.

Loks Land short-range radar site on Baffin Island, east of Iqaluit.

ATCOR Resources Ltd.

ATCOR Resources Ltd., based in Calgary, is an intermediate sized oil and gas company involved in exploration and production of oil and natural gas as well as the processing and marketing of natural gas and natural gas liquids. At the end of 1994, CU held a 31.2% interest in ATCOR. CU's ownership included 49.9% of ATCOR's Class B Common shares and 23.5% of ATCOR's Class A Non-Voting shares.

During 1994, ATCOR focused on developing existing properties that resulted from exploration programs in the previous two years. In particular, the company concentrated on the construction of new production facilities and enhancing production volumes at existing facilities.

The company has strengthened its balance sheet by reducing its level of corporate debt from a peak of $77.6 million during the second quarter of 1993 to $39.0 million at the end of 1994.

Alberta Power serviceman checks electrically-driven oil pump for ATCOR's Gooseberry oil battery north of Consort.

Exploration and Production

Crude oil and natural gas liquids production averaged 4,387 barrels per day, an increase of 12% over 1993. Natural gas sales averaged 44.9 million cubic feet per day, slightly more than the previous year.

ATCOR's property development program during the year included building oil processing and gas processing plants in west central Alberta and British Columbia, as well as four natural gas facilities in Alberta and two in British Columbia.

Natural Gas Marketing

ATCOR's natural gas marketing business continued to grow in 1994, as volumes increased 28% to average 342 million cubic feet per day. During the month of December, volumes marketed to satisfy customer requirements averaged 542 million cubic feet per day. Natural gas marketing continues to evolve with technology-driven changes such as electronic trading, increasing gas storage, futures markets, and indexed pricing. ATCOR anticipates marketing volumes will increase as much as 30 per cent in 1995.

Natural Gas Processing

The Edmonton Ethane Extraction Plant, in which ATCOR owns a one-third interest, processed an average of 278 million cubic feet per day of inlet natural gas, compared to 271 million cubic feet per day in 1993. ATCOR and its partners continue to diversify and expand the processing business, replacing declining custom processing volumes from the Leduc oilfield with additional volumes of pipeline gas.

Frontier

ATCOR holds interests in 22 significant discovery areas on which wells have been drilled and oil and/or gas have been discovered. Twenty-one of these are in the Beaufort Sea/ Mackenzie Delta and one in the Sable Island area off the coast of Nova Scotia.

ATCOR's share of established, non-producing reserves in the frontier is 50 to 70 million barrels of oil equivalent.

Management's Discussion and Analysis of Financial Condition and Results of Operations

INTRODUCTION

The following discussion and analysis of financial condition and results of operations of the Corporation for the years ended December 31, 1994 and 1993, should be read in conjunction with the Corporation's audited consolidated financial statements and related notes contained in this annual report.

The Corporation's annual audited financial statements are consolidated from three operating groups — electric utility operations, natural gas utility operations, and complementary operations including two investments accounted for on the equity basis — the Frontec companies (Frontec) and ATCOR Resources Ltd. (ATCOR). Transactions between the three operating groups are eliminated in all reporting of the Corporation's consolidated financial information.

The Corporation's electric utility operations, which include the generation, transmission and distribution of electric energy, are conducted by Alberta Power Limited (APL), The Yukon Electrical Company Limited (YECL) and Northland Utilities Enterprises Ltd. through its ownership of Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited.

The Corporation's natural gas utility operations, which include the production, purchase, transmission, transportation and distribution of natural gas, are conducted by Northwestern Utilities Limited (NUL) and Canadian Western Natural Gas Company Limited (CWNG).

The Corporation's complementary operations, which consist primarily of independent power generation and transmission projects and natural gas processing, are conducted by CU Power International Limited (CUPIL), CU Power Canada Limited (CUPCAN), CU Power Generation Limited (CUPGEN), Thames Power Limited (Thames Power), Thames Power Services Limited, Norven Holdings Inc., CU Gas Limited (CU Gas) and CU Water Limited (CU Water) and includes the Corporation's investment in Metscan, Inc., a company engaged in the design, fabrication and marketing of automatic meter reading equipment for the natural gas utility industry and other applications.

Frontec's operation and maintenance and facilities management services are conducted by Frontec Logistics Corp. (FLC) and Frontec Limited. FLC manages the Corporation's interests in several projects operated as joint ventures and also undertakes projects directly. Frontec Limited provides maintenance services and contracting services in the Northwest Territories through its Narwhal Arctic Services division. Effective January 1, 1995, the Corporation purchased the 50% interest of ATCO Ltd. (ATCO) in Frontec and ATCO's property management operations (refer to Outlook section — Complementary Operations — Frontec for the details of this purchase).

The Corporation owned a 31.2% interest in ATCOR at December 31, 1994. ATCOR, a publicly traded oil and gas company, is engaged in crude oil and natural gas exploration, development and production, and in the processing and marketing of natural gas.

UTILITY RATE REGULATION

Effective February 15, 1995, the utility operations of the Corporation in Alberta are subject to the jurisdiction of the Alberta Energy and Utilities Board (AEUB) which, among other things, is vested with broad general powers of supervision with respect to the construction and operation of electric energy and natural gas facilities within the province and broad powers of regulation in respect of rates charged for electric energy, natural gas and water.

The AEUB approves customer rates based on the revenue required to recover estimated operating expenses, depreciation and taxes payable and to provide a fair return on rate base, all in respect of future test years. Prior to February 15, 1995, the regulatory powers of the AEUB were exercised by the Public Utilities Board (PUB) and the Energy Resources Conservation Board (ERCB).

Rate base consists of the depreciated cost of utility assets and an allowance for working capital. Return on rate base is designed to meet the cost of interest on long-term debt and dividends on preferred shares and to provide the common shareholders with an opportunity to earn a fair return on their investment. The determination of a fair return to the common shareholders involves an assessment by the AEUB of many factors, including returns on alternative investment opportunities of comparable risk and the level of return which will enable a utility to attract the necessary capital to fund its operations.

The determination of customer rates is based on anticipated consumption consistent with a forecast of economic and business conditions and an estimate of customer additions. For natural gas utility operations, customer rates are also based on anticipated consumption at normal temperature which is defined as the average temperature for the previous 20 years.

In addition to any general rate applications made by the Corporation's utility subsidiaries, both NUL and CWNG file applications with the AEUB at least once a year to adjust customer rates in order to collect the actual amount of natural gas supply costs incurred in the previous winter and summer seasons. In addition, APL files an application with the AEUB yearly to adjust the price at which electric energy was sold pursuant to the Electric Energy Marketing Act in the previous year to reflect actual generation and transmission costs.

The utility operations of the Corporation in the Yukon Territory (YECL) and the Northwest Territories (Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited) are subject to regulation similar to that in effect in Alberta by regulatory authorities in those jurisdictions.

Income Tax Rebates

The Public Utilities Income Tax Transfer Act (PUITTA) provides for the rebate to customers of a portion of federal corporate income taxes paid by the Corporation which are attributable to its electric and natural gas utility operations in Alberta. For 1994 the level of rebate was 85.5% of the eligible federal corporate income taxes paid.

The federal Part VI.1 tax, which is imposed on dividends paid on taxable preferred shares issued after June 18, 1987, and Alberta corporate income taxes are not subject to rebate.

On February 27, 1995 the federal government tabled a budget in the House of Commons proposing that PUITTA be eliminated. If the proposal is enacted, customers would not see an impact on their bills until early 1996.

Utility customer rates are designed to recover estimated income taxes payable. Actual federal income taxes rebated are passed on to customers by a credit on their monthly bills. Therefore, the elimination of income tax rebate legislation will affect customers' net billings for utility services but will not have any direct effect on earnings attributable to the Corporation's Class A non-voting and Class B common shares.

Electric Energy Marketing Act

The Electric Energy Marketing Act came into effect in September 1982 with the objective of equalizing the wholesale costs of electricity throughout the province of Alberta. This equalization of generation and transmission costs (the EEMA program) is achieved by having each participating utility sell its electricity to EEMA based on its own generation and transmission costs and then purchase the electricity back from EEMA at the average generation and transmission costs of the participating utilities. APL's management continues to emphasize operating efficiencies, however APL sells electricity to EEMA at prices greater than those at

which it purchases the electricity from EEMA. This condition is primarily due to APL's larger, more remote service area and newer asset base relative to the other utilities participating in this program. The entire benefit from the difference in prices is passed on to the customers of APL. As a consequence, the operations of EEMA do not have a material effect on the Corporation's earnings.

BUSINESS RISKS

Electric and Natural Gas Utility Operations

The Corporation's utility operations are subject to the normal risks faced by all regulated utility companies. These risks include the approval of customer rates by the AEUB which permit the recovery on a timely basis of the costs of providing service, including a reasonable rate of return on investment in utility assets. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-making process.

Complementary Operations

The Corporation's complementary operations are outside its traditional utility businesses, but are related to them in terms of skills, knowledge and experience. The Corporation accounts for its complementary operations separately from its utility operations.

The Corporation's complementary operations are subject to the risks faced by any commercial enterprise in those industries and in those countries in which the Corporation operates. With the exception of CU Water, none of the complementary operations presently carried on by the Corporation are subject to rate of return regulation. The Corporation has attempted to limit its risks by entering into long-term contracts with purchasers for the output of projects and with key suppliers. The Corporation has financed its major complementary operations on a non-recourse basis, whereby the lender's recourse in the event of default is limited to the business and assets of the project in question and to the Corporation's investment therein, and not to the business and assets of the Corporation as a whole (refer to Outlook section — Complementary Operations — Capital Expenditures and Investments).

RESULTS OF OPERATIONS

CONSOLIDATED OPERATIONS

Earnings

Earnings attributable to Class A non-voting and Class B common shares for the year ended December 31, 1994, increased over 1993 by $9.4 million or 7.3% to $138.2 million. This increase was largely attributable to increased investments in assets by utility subsidiaries, higher sales of electricity, colder weather and reduced dividends on preferred shares. These positive factors were partially offset by increased operating expenses.

Earnings per share increased in 1994 to $2.22 from $2.07 in 1993. Return on common equity increased to 13.7% from 13.4% in 1993.

Earnings Attributable to Class A and Class B Shares

	1994	1993	Change
		($ millions)	
Electric Utility	**78.0**	75.9	2.1
Natural Gas Utility	**55.3**	49.4	5.9
Complementary	**4.9**	3.5	1.4
	138.2	128.8	9.4

Revenues

1994 revenues increased over 1993 by $190.0 million or 13.7% to $1,576.3 million. This increase was largely attributable to increased electric sales ($31.1 million), the impact of a full year's revenues ($19.9 million) from the Edmonton Ethane Extraction Plant (EEEP), increased natural gas transportation and storage sales ($9.2 million), PUB approval to recover higher operating expenses and costs of investments in utility assets ($7.5 million) and the impact of colder weather ($6.4 million).

Also contributing to higher revenues was the recovery of higher natural gas supply costs ($81.6 million) and the recovery of higher franchise taxes ($9.2 million).

Operating Expenses

In 1994, operating expenses rose by $183.6 million or 16.9% to $1,272.8 million.

This increase was largely attributable to increased natural gas supply costs of $81.6 million, of which $62.6 million was due to higher natural gas prices and the remainder to increased sales volumes. The amount of natural gas supply costs recorded as an expense is based on the forecast cost of natural gas included in customer rates. Any variances from forecast are deferred until the AEUB approves revised rates to either refund or collect the variance. As a consequence, changes in natural gas supply costs have a negligible effect on the Corporation's earnings.

Fuel and purchased power expense increased by $26.3 million or 29.6% to $115.1 million, primarily as a result of increased electric sales.

Operation and maintenance expenses rose by $32.5 million or 10.4% to $344.7 million, primarily as a result of the impact of a full year's operation of EEEP.

Depreciation and depletion expenses increased by $15.9 million or 11.4% to $155.7 million, primarily as a result of capital additions during 1994.

Franchise taxes rose by $9.2 million or 15.1% to $70.3 million. Franchise taxes are collected by the Corporation and remitted to municipalities. Changes in franchise taxes have a negligible effect on the Corporation's earnings.

Income taxes rose by $17.6 million or 13.4% to $148.9 million, mainly as a result of higher effective income tax rates ($9.1 million), primarily due to lower capital cost allowances being available to reduce provincial income taxes, and higher earnings before taxes ($8.5 million).

Joint Venture and Investment Income

In 1994, joint venture and investment income rose by $0.6 million or 3.5% to $17.9 million, primarily as a result of increased earnings from the McMahon Co-generation Plant, partially offset by lower earnings from Frontec and ATCOR.

Interest Expense

In 1994, interest expense rose by $3.2 million or 2.2% to $146.4 million. The increased interest expense primarily resulted from long-term debt financings of $60.0 million at 7.25% in September 1993 and $50.0 million at 8.81% in October 1994. This was partially offset by lower interest rates on refinancing of $148.2 million of long-term debt (new rates ranging from 8.73% to 8.95% versus former rates of 10.40% to 17.5%).

Dividends on Preferred Shares

In 1994, dividends on preferred shares declined by $6.9 million or 13.3% to $45.0 million. This was primarily the result of the redemption of $191.1 million of preferred shares carrying dividend rates of 7.08% to 8.74%, partially offset by the issuance during 1994 of $200.0 million of new preferred shares with dividend rates of 5.30% to 6.60%.

ELECTRIC UTILITY OPERATIONS

Earnings

Earnings from electric utility operations for 1994, which amounted to 56.4% of consolidated earnings of the Corporation, increased by $2.1 million or 2.7% to $78.0 million. The increased earnings were largely attributable to an increase in sales in APL, mainly in the industrial sector, as well as the impact of lower financing costs, partially offset by increased operating expenses and higher income taxes.

Revenues

Revenues in 1994 increased by $47.8 million or 7.9% to $650.3 million. Of this increase, $31.1 million was due to higher sales in APL and $16.7 million was due to the impact of a full year's operations of Northland Utilities (Yellowknife) Limited (NUY) and Northland Utilities (NWT) Limited (NLD), in which controlling interests were acquired in late 1993. $17.3 million of the increase in APL sales was due to higher industrial sales, mainly in the oilfield and gas and oil processing sectors ($7.6 million) and in the oilsands sector ($4.1 million). Also contributing to higher revenues was higher residential and commercial sales ($9.2 million), reflecting an improved economy and the impact of lower temperatures.

Operating Expenses

Operating expenses for 1994 increased by $50.2 million or 12.4% to $456.6 million. The increase was primarily due to an increase in fuel and purchased power costs, operation and maintenance expenses, income taxes and depreciation expense.

Fuel supply and purchased power expense increased by $26.3 million or 29.6% to $115.1 million. Of this increase, $14.8 million was due primarily to higher APL sales and $11.5 million was due to the impact of a full year's operations of NUY and NLD. Fuel costs are mostly for coal supply. To protect against volatility in coal prices, APL owns or has committed under long-term contracts sufficient coal supplies for the anticipated lives of its coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

Operation and maintenance expenses increased by $14.1 million or 10.9% to $143.3 million, primarily as a result of increased maintenance of generating plants ($2.7 million) and transmission lines ($1.3 million), the impact of a full year's operations of NUY and NLD ($2.0 million) and higher customer billing costs and insurance costs ($1.5 million).

Income taxes increased by $4.3 million or 5.5% to $82.2 million in 1994, mainly as a result of higher effective income tax rates ($3.6 million), primarily due to lower capital cost allowances being available to reduce provincial income taxes.

Depreciation expense increased by $4.3 million or 5.0% to $89.7 million in 1994. This increase was primarily as a result of capital additions during 1994.

Interest Expense

Interest expense increased by $0.2 million or 0.2% to $92.6 million in 1994 primarily due to the impact of a full year's interest expense for NUY and NLD, partially offset by a decrease in APL's interest expense. The decrease in APL's interest expense primarily resulted from lower interest rates on refinancing of $83.9 million of long-term debt (new rates ranging from 8.73% to 8.95% versus former rates of 10.62% to 17.5%). This was partially offset by additional issues of $25.0 million at 7.25% in September 1993 and $22.5 million at 8.81% in October 1994.

Dividends on Preferred Shares

Dividends on preferred shares declined by $4.6 million or 15.0% to $26.0 million in 1994. This decrease was primarily the result of the redemption of $122.2 million of preferred shares carrying dividend rates of 7.08% to 8.74%, partially offset by the issuance during 1994 of $117.5 million of new preferred shares with dividend rates of 5.30% to 6.60%.

NATURAL GAS UTILITY OPERATIONS

Earnings

Earnings from natural gas utility operations for 1994, which amounted to 40.0% of consolidated earnings of the Corporation, increased by $5.9 million or 11.9% to $55.3 million. Earnings improved primarily as a result of AEUB (formerly the PUB and the ERCB) approval to recover higher operating expenses and costs of investments in utility assets ($4.2 million), higher sales due to colder than normal temperatures ($3.6 million) and customer growth of 2.1% ($3.6 million), partially offset by increased operating expenses ($6.6 million).

Temperatures in 1994 were 2.3% colder than normal. If temperatures had been normal during 1994, the Corporation's earnings would have been reduced by $2.5 million.

Revenues

Revenues in 1994 increased by $116.1 million or 15.0% to $889.9 million. Contributing to the higher revenues was the approval by the AEUB (formerly the PUB and the ERCB) to recover higher operating expenses and costs of investments in utility assets ($7.5 million), the impact of temperatures which were 3.2% colder than 1993 ($6.4 million) and higher sales reflecting growth in the number of customers ($6.4 million).

Also contributing to higher revenues, with a negligible effect on earnings, was the recovery of higher natural gas supply costs ($81.6 million) and the recovery of higher franchise taxes ($8.4 million).

Operating Expenses

Operating expenses for 1994 increased by $109.3 million or 16.4% to $774.1 million. This increase was primarily due to higher natural gas supply costs.

Natural gas supply costs, which represent approximately 53.0% of total operating expenses, increased by $81.6 million or 24.9% to $409.9 million, primarily due to higher natural gas prices ($62.6 million) and increased sales volumes due to colder than normal temperatures ($13.5 million).

Income taxes increased by $9.7 million or 20.6% to $56.9 million in 1994, mainly due to higher earnings before taxes ($5.7 million) and higher effective income tax rates ($4.0 million), primarily due to lower capital cost allowances being available to reduce provincial income taxes.

Franchise taxes increased by $8.4 million or 14.8% to $63.5 million in 1994 as a result of increased customer billings.

Depreciation expense rose $6.0 million or 11.2% to $59.7 million in 1994, primarily as a result of capital additions during 1993 and 1994.

Operation and maintenance expenses increased by $3.5 million or 2.0% to $175.4 million in 1994, primarily as a result of higher prices for operating supplies ($4.6 million), partially offset by lower labour costs ($1.0 million).

Interest Expense

Interest expense decreased by $0.2 million or 0.4% to $49.4 million in 1994. The decrease in interest expense primarily resulted from lower interest rates on refinancing of $64.1 million of long-term debt (new rates ranging from 8.73% to 8.95% versus former rates of 10.62% to 17.5%). This was partially offset by additional issues of $35.0 million at 7.25% in September 1993 and $27.5 million at 8.81% in October 1994.

Dividends on Preferred Shares

Dividends on preferred shares declined by $2.2 million or 14.3% to $13.2 million in 1994. This decrease was primarily the result of the redemption of $68.9 million of preferred shares carrying dividend rates of 7.08% to 8.74%, partially offset by the issuance during 1994 of $82.5 million of new preferred shares with dividend rates of 5.30% to 6.60%.

COMPLEMENTARY OPERATIONS

Earnings

Earnings from complementary operations for 1994, which amounted to 3.6% of consolidated earnings of the Corporation, increased by $1.4 million or 40.0% to $4.9 million. This increase was due to higher earnings from CUPIL and CU Gas partially offset by lower earnings from ATCOR and Frontec.

Earnings From Complementary Operations

	1994	1993	Change
		($ millions)	
CUPIL	**5.4**	1.5	3.9
CU Gas	**1.3**	(0.4)	1.7
Frontec	**5.4**	6.3	(0.9)
ATCOR	**1.9**	2.3	(0.4)
	14.0	9.7	4.3
Less: Financing Costs	**6.2**	5.6	0.6
Other	**2.9**(1)	0.6	2.3
	4.9	3.5	1.4

Note:
(1) Primarily consists of a writedown ($1.9 million) of the carrying value of the Corporation's investment in ATCOR to the amount of its ownership interest in the underlying net book value and administrative costs relating to Complementary Operations.

CUPIL

Earnings from CUPIL amounted to $5.4 million in 1994, compared to $1.5 million in 1993. This increase reflected the impact of a full year's operations at the McMahon Co-generation Plant and increased earnings from construction supervision and management services provided for the construction of a 1,000-megawatt, $1.4 billion, natural gas-fired, combined-cycle generating plant at Barking in London, England (the Barking Project).

CU Gas

CU Gas generated earnings of $1.3 million during 1994 compared to a loss of $0.4 million during 1993. The improvement in earnings is primarily due to the impact of a full year's earnings from EEEP.

During 1994, the Corporation's investment in Metscan, Inc. (Metscan) of Lima, New York was written down from $4.1 million to $2.0 million as a result of continued losses reported by Metscan and dilution of the investment caused by the decision of management not to participate in the last Metscan financing.

Frontec

In 1994, earnings reported by the Corporation from its interest in Frontec decreased by $0.9 million or 14.3% to $5.4 million, primarily due to lower earnings from the North Warning System contract.

ATCOR

The earnings reported by the Corporation from its interest in ATCOR were $1.9 million in 1994 compared to $2.3 million in 1993.

LIQUIDITY AND CAPITAL RESOURCES

Cash provided from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through the issuance of long-term debt, preferred shares and common equity. Commercial paper borrowings and bank loans are used to provide flexibility in the timing and amounts of long-term financing.

It is the policy of the Corporation to pay dividends quarterly on its Class A non-voting and Class B common shares. The matter of an increase in the quarterly dividend is addressed in the first quarter of each year. For the first quarter of 1995, the quarterly dividend payment has been increased by $0.005 to $0.365 per share. The payment of any dividend on Class A non-voting and Class B common shares is at the discretion of the board of directors and depends on the financial condition of the Corporation and other factors. Since its inception as a holding company in 1972, the Corporation has increased its annual common share dividend for 23 consecutive years.

Cash provided from operations amounted to $257.6 million in 1994, compared to $267.6 million in 1993. Dividends on Class A non-voting shares and Class B common shares amounted to $89.5 million in 1994 compared to $88.2 million in 1993. This dividend increase primarily reflected an increase in the annual dividend rate from $1.42 per share in 1993 to $1.44 in 1994. Cash provided from operations net of Class A non-voting and Class B common share dividends represented approximately 75% of the consolidated cash requirements in 1994 and is expected to represent 60% in 1995. The expected decrease to 60% results from the Corporation's acquisition in January 1995 of certain assets from Norcen Energy Resources Limited (refer to Outlook section — Natural Gas Utility Operations — Capital Expenditures and Complementary Operations — CU Gas for details related to this acquisition).

Investment in utility property, plant and equipment was $213.7 million in 1994 compared to $237.2 million in 1993. Expenditures for property, plant and equipment and net investments in complementary operations were $25.8 million in 1994, versus $18.1 million in 1993. Total expenditures for 1995 are expected to be approximately $250 million for utility operations and approximately $60 million for complementary operations.

To finance 1994 utility operations, including the redemption of $148.2 million of long-term debt having interest rates ranging from 10.40% to 17.5%, the Corporation issued $185.0 million of long-term debt with interest rates ranging from 8.73% to 8.95%. In addition, to finance complementary operations, £5.5 million ($14.4 million) was borrowed under a term loan credit facility with interest rates based on the London Interbank Offered Rate (LIBOR), which averaged 6.26% during 1994.

During 1994, $191.1 million of preferred shares having dividend rates ranging from 7.08% to 8.74% were redeemed and the Corporation issued $200.0 million of preferred shares with dividend rates ranging from 5.30% to 6.60%.

On December 13, 1994, the Corporation's guarantee of up to $60.0 million of financing for the McMahon Co-generation Plant, a 120-megawatt joint venture independent power project located in Taylor, British Columbia, was removed. Recourse of the lenders is now limited to the Corporation's equity investment in the project, amounting to $9.7 million.

The Corporation has guaranteed the provision of up to £24.1 million ($52.9 million) of equity and subordinated loans to Barking Power Limited. To meet this obligation, the Corporation has provided a guarantee of all advances made and to be made under a £20.0 million ($43.9 million) loan agreement between CUPGEN and a Canadian chartered bank. At December 31, 1994, £16.4 million ($35.9 million) of equity and subordinated loans had been provided to Barking Power Limited, of which £15.5 million ($34.0 million) had been advanced under the loan agreement.

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

During 1994, Canadian Bond Rating Service Inc. (CBRS) upgraded the ratings on the Corporation's Debentures and Medium Term Note Debentures to A+ from A+ (low) and reaffirmed the credit ratings on commercial paper and preferred shares at A-1+ and P-1, respectively. Dominion Bond Rating Service Limited (DBRS) reaffirmed the Corporation's debt, commercial paper and preferred share ratings at AA (low), R-1 (middle) and Pfd-1, respectively.

OUTLOOK

ELECTRIC UTILITY OPERATIONS

Electric Energy Marketing Act

On October 18, 1994, the Minister of Energy tabled a report (the "Report") in the Alberta Legislature outlining proposed changes to the electric utility industry in Alberta. The Report represents a consensus reached by Alberta electric utilities (including APL), customers, independent power producers, environmental interest groups and the Alberta government.

Currently, under the EEMA program, all customers throughout the province of Alberta pay the same average wholesale price of electricity. The Report recommends, among other things, that the averaging process continue for transmission and existing generating facilities, but that the costs of future generating facilities not be averaged. Each utility would be responsible for obtaining the new electric generating capacity needed to meet the needs of customers in its service areas. Changes to existing legislation are expected to be introduced in the Alberta Legislature during 1995 and are expected to be implemented in early 1996.

The changes contemplated by the Report are not expected to have a significant impact in the short term because existing generating capacity in Alberta is expected to be sufficient to meet the needs of customers for the rest of the decade. However, over the longer term, as new electric generating capacity is required, the prices paid by Alberta customers for electricity may vary depending on which utility supplies their electricity. The Corporation does not expect that the proposed changes will have a material effect on the Corporation's earnings.

Regulatory Matters

On December 19, 1994, an association of industrial power customers filed an application with the AEUB (formerly the PUB and the ERCB) requesting a review of the rates charged by APL for 1994. On March 1, 1995, a similar application was filed with the AEUB for 1995. A preliminary hearing to determine whether or not there is sufficient cause to hold a general rate case is expected to be held in April.

Capital Expenditures

Capital expenditures in the Corporation's electric utility operations are expected to average $89 million per year over the next five years, down 38% from the $143 million per year average over the past five years. Electric energy requirements in APL's service areas are not expected to exceed the Corporation's generating capacity within the next five years. As a consequence, the Corporation is not planning to add significantly to generating plant rate base during this period.

NATURAL GAS UTILITY OPERATIONS

Gas Utilities Statutes Amendment Act

In 1994, industry worked with the Alberta government to draft the regulations surrounding Bill 51, the Gas Utilities Statutes Amendment Act, which will provide the framework for residential, commercial and institutional customers to purchase their natural gas supply directly from producers, subject to certain conditions. Although it was anticipated that the government would implement this legislation in 1994, it is now expected to become law in 1995. Although the legislation could result in some core market customers switching from sales to transportation service, neither total throughput nor the Corporation's earnings are expected to be materially affected.

Capital Expenditures

Capital expenditures to provide for customer growth and to meet the needs of existing customers in the Corporation's natural gas utility operations are expected to average $110 million per year over the next five years, down 9% from the $121 million per year average of the past five years.

On January 26, 1995, NUL and CU Gas acquired certain assets from Norcen Energy Resources Limited for a price of $80.0 million. The NUL assets consist of a transmission line (the IGS system) in the vicinity of Edmonton, a natural gas pipeline system from Wabamun to Hinton known as the NCOL line, and natural gas transportation and sale contracts relating to the systems.

COMPLEMENTARY OPERATIONS

The Corporation's strength has been its core utility operations which provide consistent earnings. The Corporation intends to enhance this stable foundation with earnings from its complementary operations. With the completion of the major projects currently under construction, the Corporation expects that complementary operations will be contributing in a significant way to the Corporation's earnings by 1997.

CUPIL

Construction of the Barking Project commenced in 1992 and is currently on schedule and on budget. Synchronization of the first two turbines was achieved in December 1994. Commercial operation of the first block (400 megawatts) is scheduled to begin in April 1995. The second block (600 megawatts) is expected to come on stream in June 1995.

CUPIL continues to pursue independent power projects in Canada, Europe, Australia and the United States.

CU Gas

On January 26, 1995, CU Gas and NUL acquired certain assets from Norcen Energy Resources Limited for a price of $80.0 million. The CU Gas assets consist of three natural gas processing plants, two compressor stations and 240 km of gathering lines in the Edmonton area. Natural gas production from the producing properties connected to the system is purchased by CU Gas and sold either under contracts with a number of industrial customers and a distribution company or into the Alberta spot market. Natural gas production from the producing properties is also gathered and processed for a fee.

CU Gas continues to explore natural gas gathering and processing and storage opportunities in Alberta and in the international market place.

CU Water

CU Water continues to examine water project opportunities in Canada and in the United States.

Frontec

Effective January 1, 1995, the Corporation purchased ATCO's 50% interest in Frontec and ATCO's property management operations. The total purchase price for both acquisitions was $35.7 million and was paid by the issuance of 935,679 Class A non-voting shares and 599,756 Class B common shares of the Corporation. The property management operations will be conducted by Frontec Limited. This acquisition by the Corporation will facilitate Frontec's efforts to grow as an independent company by reducing the administrative costs associated with joint ownership and allow for a single board of directors and management team to direct Frontec's ongoing development of strategies and objectives.

Frontec has completed a corporate restructuring with the establishment of Frontec Corporation as the parent company of FLC. In addition, Frontec Limited is to be renamed Frontec Services Limited.

FLC manages the Corporation's interest in a seven year $415 million contract with the government of Canada to operate and maintain the North Warning System until March 31, 1995.

In 1994, a new venture between FLC and Pan Arctic Inuit Logistics Corporation was awarded a $255 million contract to operate and maintain the North Warning System from April 1, 1995 to March 31, 2000. The agreement provides for the sharing of profits based upon each participant meeting certain performance targets. Northland Utilities Enterprises Ltd. will continue to participate in 10% of Frontec's share of the profits from the agreement. The venture has entered into a subcontract with FLC to provide all services under the contract on a firm fixed price basis.

FLC has a joint venture with Piquniq Management Corporation, an Alaska-based company, to operate and maintain the Alaska Radar System. This contract is for one year and has four one year renewal options. If all renewal options are exercised, the total revenues will be U.S. $100 million. FLC's share is 49% of this total. The joint venture assumed operations responsibility on October 1, 1994.

Frontec continues to pursue operation and maintenance and facilities management opportunities in North America and internationally.

Capital Expenditures and Investments

Over the next five years, the Corporation's share of the capital expenditures related to its complementary operations is expected to be approximately $400 million, of which approximately $250 million will be financed on a non-recourse basis. One of the largest of these expenditures is expected to be in 1995 for the Barking Project, where the Corporation's share of the capital expenditures is approximately $66 million, of which approximately $57 million will be financed on a non-recourse basis.

CHANGE IN ACCOUNTING POLICY

The Corporation has accounted for joint ventures by the equity method. Effective January 1, 1995, the Corporation changed to the proportionate consolidation method to conform with the recommendations of the Canadian Institute of Chartered Accountants. This change will have no effect on the net earnings of the Corporation, but the Corporation's pro rata share of the assets, liabilities, revenues and expenses of the joint ventures will be reflected in the Corporation's consolidated financial statements.

March 8, 1995

Financial Statements

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The preparation of the consolidated financial statements, management's discussion and analysis and all other financial information relating to the Corporation contained in this annual report is the responsibility of management. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management depends upon internal accounting control systems to meet its responsibility for reliable and accurate reporting. These control systems are subject to periodic review by the Corporation's internal auditors.

Price Waterhouse, the Corporation's independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

The Board of Directors, through its Audit Committee comprised of 5 non-management directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and financial matters, gain assurance that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee.

C. S. RICHARDSON
Deputy Chairman of the Board
and Chief Financial Officer

D. T. DAVIS
Vice President
and Controller

AUDITORS' REPORT

To the Shareholders of
Canadian Utilities Limited

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 1994 and 1993 and the consolidated statements of earnings and retained earnings and changes in cash position for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 1994 and 1993 and the results of its operations and the changes in its cash position for the years then ended in accordance with generally accepted accounting principles.

Price Waterhouse
Chartered Accountants

Edmonton, Canada
February 1, 1995

CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS

(Millions of Canadian Dollars)

	Note	Year ended December 31 1994	1993
Revenues		**$1,576.3**	$1,386.3
Operating Expenses			
Natural gas supply		**409.9**	328.3
Fuel and purchased power		**115.1**	88.8
Operation and maintenance		**344.7**	312.2
Depreciation and depletion		**155.7**	139.8
Franchise taxes		**70.3**	61.1
Property and other taxes		**28.2**	27.7
Income taxes	1	**148.9**	131.3
		1,272.8	1,089.2
Operating Income		**303.5**	297.1
Allowance for Funds Used		**4.0**	5.0
Joint Venture and Investment Income	2	**17.9**	17.3
Interest and Other Income		**4.2**	4.5
		26.1	26.8
Earnings before Financing Charges		**329.6**	323.9
Interest Expense		**146.4**	143.2
Dividends on Preferred Shares	6	**45.0**	51.9
		191.4	195.1
Earnings Attributable to Class A and Class B Shares		**138.2**	128.8
Retained Earnings at Beginning of Year		**499.5**	458.9
		637.7	587.7
Dividends on Class A and Class B Shares	7	**89.5**	88.2
Retained Earnings at End of Year		**$ 548.2**	$ 499.5
Earnings per Class A and Class B Share (dollars)		**$ 2.22**	$ 2.07
Dividends paid per Class A and Class B Share (dollars)		**$ 1.44**	$ 1.42

CONSOLIDATED BALANCE SHEET

(Millions of Canadian Dollars)

	Note	December 31 1994	1993
ASSETS			
Current Assets			
Cash		**$ 9.7**	$ 20.3
Accounts receivable		**207.3**	203.2
Inventories		**70.4**	65.9
Prepaid expenses		**10.5**	12.0
		297.9	301.4
Investments	2	**131.1**	98.9
Property, Plant and Equipment	3	**2,916.8**	2,876.4
Deferred Financing Charges		**17.4**	14.2
Other Assets		**23.9**	14.2
		$3,387.1	$3,305.1
LIABILITIES AND CAPITALIZATION			
Current Liabilities			
Due to bank		**$ 17.7**	$ 21.5
Accounts payable and accrued liabilities		**136.4**	144.5
Accrued interest and dividends		**33.1**	34.5
Income and other taxes payable		**38.7**	47.6
		225.9	248.1
Deferred Credits		**16.4**	14.2
Capitalization			
Notes payable	4	**98.7**	96.9
Long-term debt	5	**1,324.8**	1,282.4
Preferred shares	6	**689.0**	680.1
		2,112.5	2,059.4
Class A and Class B shareholders' equity	7	**1,032.3**	983.4
		3,144.8	3,042.8
		$3,387.1	$3,305.1

Approved by the Board:

J. D. Wood
Director

B. K. French
Director

CONSOLIDATED STATEMENT OF CHANGES IN CASH POSITION

(Millions of Canadian Dollars)

	Year ended December 31	
	1994	1993
CASH PROVIDED FROM OPERATIONS		
Earnings attributable to Class A and Class B shares	**$ 138.2**	$ 128.8
Depreciation and depletion	**155.7**	139.8
Joint venture and investment income, net of distributions	**(7.7)**	(6.7)
Other	**(1.9)**	(.1)
Allowance for funds used — shareholders' equity	**(1.5)**	(1.8)
Decrease (increase) in working capital	**(25.2)**	7.6
	257.6	267.6
DIVIDENDS		
Class A and Class B shares	**89.5**	88.2
	168.1	179.4
FINANCING		
Increase in notes payable	**1.8**	36.7
Issue of long-term debt	**199.5**	71.9
Repayment of long-term debt	**(157.1)**	(28.9)
Issue of preferred shares	**200.0**	125.0
Preferred shares purchased or redeemed	**(191.1)**	(144.2)
Issue of Class A shares	**.2**	.5
Other	**(6.8)**	(6.6)
	46.5	54.4
Total Cash for Investment	**214.6**	233.8
INVESTMENT		
Capital expenditures	**215.1**	259.3
Contributions for extensions to plant	**(26.4)**	(23.3)
Allowance for funds used — shareholders' equity	**(1.5)**	(1.8)
	187.2	234.2
Investments — net	**23.9**	12.3
Sale of ATCOR Class A shares		(14.4)
Disposal of property, plant and equipment	**7.7**	2.5
Other	**2.6**	1.9
	221.4	236.5
Decrease in Cash	**$ (6.8)**	$ (2.7)

Cash is excluded from working capital. Cash is defined as "Cash" less "Due to bank".

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

December 31, 1994

Financial Statement Presentation

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles and conform in all material respects with the International Accounting Standards adopted by the International Accounting Standards Committee.

The consolidated financial statements include the accounts of the Corporation and its subsidiaries. The major subsidiaries are Alberta Power Limited (regulated electric utility), Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited (regulated natural gas utilities) and CU Power International Limited (independent power producer). The Corporation uses the equity method to account for joint ventures and investments (including Thames Power Limited, the Frontec Group and ATCOR Resources Ltd.) in which it has a significant interest, and includes its share of their net earnings in investment income.

Regulation

The electric and natural gas utility subsidiaries are regulated primarily by the Public Utilities Board of Alberta (PUB) and the Energy Resources Conservation Board of Alberta (ERCB), which administer acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The PUB may award interim rates, subject to final determination. Decisions made by these authorities and management which impact on utility accounting policies are reflected in the consolidated financial statements after the date of decision.

Effective February 15, 1995 the PUB and ERCB were amalgamated to become the Alberta Energy and Utilities Board (AEUB).

Revenue Recognition

Revenues are recognized on the accrual basis. Significant additional revenues or refunds resulting from PUB decisions are recorded in the year to which they relate. Other adjustments are recorded in the current year.

The Electric Energy Marketing Act (EEMA) has the objective of reducing rate differentials for Alberta customers. Under the EEMA process, energy is purchased from the electric subsidiary and two other electric utilities based on each utility's generation and transmission costs and resold to each utility at an average price. Costs subject to equalization by EEMA are reviewed and approved by the PUB. The differential between the selling and buying prices is reflected in customer rates and is recorded as revenue (or expense).

Natural Gas Supply

Natural gas supply expense is based on the forecast cost of natural gas included in customer rates. Variances from forecast costs are deferred until such time as approval from the PUB is obtained for refund to or collection from customers through revised rates and natural gas supply expense is adjusted accordingly.

Income Taxes

Electric and Natural Gas Subsidiaries

The PUB has directed the Corporation to use the normalized-all taxes paid method to account for Federal income taxes and the flow-through method to account for Provincial income taxes.

The normalized-all taxes paid method does not result in a deferral of income taxes as timing differences between accounting earnings and taxable income are eliminated. The flow-through method results in a deferral of income taxes.

No provision has been made in the consolidated financial statements for deferred income taxes arising from the use of the flow-through method as the income tax component of rates approved by the PUB is designed to recover only income taxes currently payable. The customer in future years will bear an additional charge in the event of a reversal of these unbooked deferred income taxes.

Other Operations

The tax allocation method of accounting for income taxes is used for operations other than regulated electric and natural gas utilities.

Inventories

Inventories are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment

The utility subsidiaries include in capital expenditures an allowance for funds used during construction and on plant held for future use at rates approved by the PUB for debt and equity capital.

Plant held for future use is plant which is in service or is capable of service, the cost of which has been excluded from rate base. The PUB will determine when this plant can be included in rate base.

Certain utility additions are made with the assistance of non-refundable cash contributions where the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate. Property, plant and equipment is disclosed net of unamortized contributions.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates approved by the PUB on major classes of assets vary from 1.5% to 10.2%, resulting in a composite rate of 3.7% for electric and 3.9% for natural gas assets. For certain assets these approved rates include a provision for future removal or site restoration costs.

On retirement of depreciable utility assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Deferred Financing Charges

Expenses of issuing long-term debt are amortized over the weighted average life of the debt, and expenses of issuing preferred shares are amortized over the expected life of the issue. Unamortized premiums and issue costs of redeemed long-term debt and preferred shares are amortized over the life of the issue funding the redemption.

Notes Payable

Under a bank loan agreement which is renewed on a continuing basis, the Corporation may issue commercial paper or borrow directly from the bank. These borrowings allow the Corporation to manage the amount and timing of long-term debt, preferred share and equity issues and are classified as long term.

Current Maturities of Long-Term Debt

When the Corporation intends to refinance current maturities on a long-term basis and there is either a written undertaking from an underwriter to act on the Corporation's behalf or sufficient capacity under the bank loan agreement to issue commercial paper or assume bank loans, then current maturities of long-term debt are classified as long term.

Preferred Shares

The financing requirements of the regulated utility subsidiaries of the Corporation result in preferred dividends being recorded in the same manner as interest costs.

Retirement Benefits

The Corporation and its subsidiaries have defined benefit pension plans covering substantially all employees. Employees participate through contributions to the plans which provide for pensions based on length of service and final average earnings. The cost of pension benefits is determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Plan assets are valued at market adjusted for a three year averaging of unrealized gains or losses.

Adjustments resulting from plan enhancements, experience gains and losses and changes in assumptions are amortized over the estimated average remaining service life of employees.

The cost of other benefits, including health, dental and life insurance to retirees and their dependants, is expensed as paid.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 1994
(tabular amounts in millions of dollars)

1. Income taxes

The expected rate of income tax on accounting earnings would equal the statutory rate in the absence of permanent differences and the effect of flow-through accounting for Provincial income taxes in the electric and natural gas utility subsidiaries. The following table describes these exceptions and their effect on the statutory rate:

	1994		1993	
Earnings before income taxes	**$332.1**	**%**	$312.0	%
Income taxes, at statutory rate	**146.6**	**44.1**	138.1	44.3
Allowance for funds used	**(1.0)**	**(.3)**	(1.2)	(.4)
Depreciation of capitalized allowance for funds used	**3.5**	**1.1**	3.6	1.2
Crown royalties and other non-deductible Crown payments	**3.4**	**1.0**	3.0	1.0
Earned depletion and resource allowance	**(5.5)**	**(1.7)**	(5.2)	(1.7)
Provincial timing differences	**(3.6)**	**(1.1)**	(5.8)	(1.9)
Large Corporations Tax	**5.9**	**1.8**	4.1	1.3
Joint venture and investment income	**.7**	**.2**	(1.0)	(.3)
Other	**(1.1)**	**(.3)**	(4.3)	(1.4)
Income taxes	**148.9**	**44.8**	131.3	42.1
Net earnings before preferred dividends	**$183.2**		$180.7	

Income taxes includes deferred income taxes of $1.1 million (1993 — $1.8 million). Accumulated deferred income taxes of $1.9 million (1993 — $1.0 million) are included in deferred credits.

Deferred income taxes of approximately $172.6 million (1993 — $168.0 million) are not included in the consolidated financial statements.

2. Investments

	Ownership Interest	Investment 1994	Investment 1993	Income 1994	Income 1993
Equity method:					
ATCOR Resources Ltd.	31.2%	**$ 54.2**	$52.3	**$ 1.9**	$ 2.3
Joint ventures					
Operating					
McMahon Co-generation Plant	50%	**10.8**	1.5	**6.2**	1.3
Fort Nelson Transmission Line	50%	**6.8**	7.2	**1.5**	1.5
Frontec Group	50-55%	**19.5**	11.3	**10.4**	11.5
Northland Utilities Enterprises Ltd.					.7
Under development					
Thames Power Limited					
Barking Power Limited — shareholder advances	25.5%	**35.9**	20.7		
Total joint ventures		**73.0**	40.7	**18.1**	15.0
Total equity method		**127.2**	93.0	**20.0**	17.3
Cost method		**3.9**	5.9	**(2.1)**	
		$131.1	$98.9	**$17.9**	$17.3

Income from the investments in ATCOR Resources Ltd. and Northland Utilities Enterprises Ltd., which are incorporated companies, is recorded on an after-tax basis.

McMahon Co-generation Plant

The plant was commissioned in 1993 and, upon completion of construction in 1994 and in accordance with the terms of the financing agreement, the Corporation contributed $9.7 million of equity to the Joint Venture.

Northland Utilities Enterprises Ltd.

On September 30, 1993, upon acquisition of a controlling interest, the Corporation changed from the equity to the consolidation method of accounting for its investment.

Barking Power Project

The Corporation has a 25.5% interest in Barking Power Limited through its 50% interest in Thames Power Limited. Barking Power Limited has an agreement with a consortium of banks for credit facilities of £661.0 million ($1,451.6 million), including standby facilities, to finance a 1,000 MW combined cycle gas turbine generating plant at Barking in London, England. Security for these credit facilities is limited to the assets of Barking Power Limited and is non-recourse to the other assets of the Corporation. The agreement is subject to the obligation of the shareholders to advance £94.4 million ($207.3 million) of equity and subordinated debt, of which the Corporation's share is £24.1 million ($52.9 million). These advances are denominated in pounds sterling and are translated at the current exchange rate.

Equity in joint venture operations

The Corporation's investment in and proportionate share of joint venture operations accounted for by the equity method is summarized as follows:

	1994	1993
Balance sheet		
Net working capital	**$ 2.3**	$ (.7)
Property, plant and equipment — in service	**53.7**	54.6
— under construction	**303.8**	190.9
Deferred items	**(.3)**	(.3)
Long-term debt — recourse		(45.9)
— non-recourse	**(286.5)**	(157.9)
Investment in joint ventures	**$ 73.0**	$ 40.7

Non-recourse debt is secured only by joint venture assets.

	1994	1993
Statement of earnings		
Revenues	**$ 90.1**	$ 74.4
Expenses	**64.6**	55.7
Depreciation	**3.6**	2.2
Earnings before interest and income taxes	**21.9**	16.5
Other income	**.8**	.4
Financing charges	**4.7**	1.3
Income taxes	**(.1)**	.6
Income from joint ventures	**$ 18.1**	$ 15.0

3. Property, plant and equipment

	1994 Cost	1994 Accumulated Depreciation	1993 Cost	1993 Accumulated Depreciation
Electric plant and equipment	**$2,686.7**	**$ 800.8**	$2,601.4	$ 723.8
Natural gas plant and equipment	**1,756.7**	**529.2**	1,643.5	481.4
Plant held for future use	**36.9**		37.4	
Construction work in progress	**17.9**		31.4	
Other plant and equipment	**43.3**	**4.4**	47.0	2.6
Land	**22.9**		22.4	
	$4,564.4	**$1,334.4**	$4,383.1	$1,207.8

	1994	1993
Property, plant and equipment, less accumulated depreciation	**$3,230.0**	$3,175.3
Unamortized contributions for extensions to plant	**313.2**	298.9
Property, plant and equipment	**$2,916.8**	$2,876.4

Accumulated depreciation includes an amount provided for future removal or site restoration costs of $82.8 million (1993 — $67.2 million).

4. Notes payable

At December 31, 1994, the Corporation had outstanding commercial paper of $98.7 million (1993 — $96.9 million), at interest rates ranging from 5.75% to 6.32% with maturities to February 17, 1995.

Under the bank loan agreement, which currently provides a line of credit of up to $100.0 million to December 14, 1995, the Corporation has agreed to maintain an unused amount of not less than 50% of the commercial paper outstanding. There were no bank loans outstanding under this agreement at December 31, 1994 and 1993.

5. Long-term debt

	1994	1993
Debentures		
1974 Series 9⅛% due March 1994 (sinking fund)	**$**	$ .9
1984 Series 13.10% due June 1994		100.0
1982 Series 17.5% due March 1997 (sinking fund)	**27.0**	30.0
1994 Medium Term Note 8.95% due July 1997	**35.0**	
1988 Series 11.25% due September 1998	**50.0**	50.0
1979 Series 10.40% due July 1999 (sinking fund)		39.0
1994 Medium Term Note 8.81% due April 2000	**50.0**	
1980 Series 12% due July 2000 (sinking fund)	**47.0**	53.0
1993 Series 7.25% due September 2003	**60.0**	60.0
1994 Series 8.73% due June 2004	**100.0**	
1986 Series 9.85% due October 2006	**100.0**	100.0
1986 Second Series 10.25% due December 2006	**90.0**	90.0
1987 Series 12% due October 2007	**125.0**	125.0
1989 Series 10.20% due November 2009	**125.0**	125.0
1990 Series 11.40% due August 2010	**125.0**	125.0
1990 Second Series 11.77% due November 2020	**100.0**	100.0
1991 Series 9.92% due April 2022	**125.0**	125.0
1992 Series 9.40% due May 2023	**100.0**	100.0
	1,259.0	1,222.9
Barking Power Project — term loan credit facility	**34.0**	19.6
Other long-term obligations, at rates ranging from 7.62% to 14.87%	**31.8**	39.9
	$1,324.8	$1,282.4

The Corporation issued $100.0 million of 8.73% Debentures 1994 Series for cash. The proceeds were used to redeem the 13.10% Debentures 1984 Series at maturity.

The Corporation issued $35.0 million of 8.95% Medium Term Note Debentures for cash. The proceeds were used to redeem the outstanding 10.40% Debentures 1979 Series.

The Corporation also issued $50.0 million of 8.81% Medium Term Note Debentures for cash.

The Corporation has entered into an agreement to borrow, under a term loan credit facility repayable over 4 years commencing in 1997, £20.0 million ($43.9 million) to finance its interest in the Barking Power Project. As at December 31, 1994 the Corporation has borrowed £15.5 million ($34.0 million). The interest rate is based on the London Interbank Offered Rate (LIBOR) and during 1994 averaged 6.26%.

Maturities

Annual repayment of maturing issues, other long-term obligations and sinking fund requirements for each of the next five years are:

	Maturing Issues	Other Long-term Obligations	Sinking Fund Requirements	Total	Amount to be Refinanced
1995	$	$ 3.8	$8.0	$11.8	$11.8
1996		21.4	8.0	29.4	29.4
1997	56.0	10.5	5.0	71.5	61.2
1998	50.0	12.0	5.0	67.0	56.8
1999		7.7	5.0	12.7	5.9

6. Preferred shares

			Dividends	
	1994	1993	**1994**	1993
Canadian Utilities Limited	**$669.0**	$660.1	**$44.2**	$51.1
Northwestern Utilities Limited	**10.5**	10.5	**.4**	.4
Canadian Western Natural Gas Company Limited	**9.5**	9.5	**.4**	.4
	20.0	20.0	**.8**	.8
	$689.0	$680.1	**$45.0**	$51.9

Canadian Utilities Limited

Authorized:

40,000 5% Cumulative Redeemable Preferred Shares.

150,000 Series Preferred Shares, issuable in series, designated as Cumulative Redeemable Preferred Shares and ranking pari passu with the 5% Cumulative Redeemable Preferred Shares.

An unlimited number of Series Second Preferred Shares, issuable in series, designated as Cumulative Redeemable Second Preferred Shares.

6. **Preferred shares** (continued)

Issued:

	1994		1993	
	Shares	**Amount**	Shares	Amount
Cumulative Redeemable				
Preferred Shares				
5%	**40,000**	**$ 4.0**	40,000	$ 4.0
4¼% Series	**15,000**	**1.5**	15,000	1.5
6% Series	**50,000**	**5.0**	50,000	5.0
		10.5		10.5
Cumulative Redeemable				
Second Preferred Shares				
Non-retractable				
7.30% Series C	**734,180**	**18.4**	737,780	18.5
8.74% Series I			3,588,966	89.7
7.70% Series L	**604,570**	**15.1**	2,400,000	60.0
7.08% Series M			2,256,650	56.4
7.875% Series O	**3,000,000**	**75.0**	3,000,000	75.0
		108.5		299.6
Retractable				
7.10% Series N	**4,000,000**	**100.0**	4,000,000	100.0
8.00% Series P	**5,000,000**	**125.0**	5,000,000	125.0
5.90% Series Q	**5,000,000**	**125.0**	5,000,000	125.0
5.30% Series R	**6,000,000**	**150.0**		
6.60% Series S	**2,000,000**	**50.0**		
		550.0		350.0
		$669.0		$660.1

On April 14, 1994, the Corporation issued $150.0 million of Cumulative Redeemable Second Preferred Shares Series R for cash. The proceeds were used to redeem the outstanding Cumulative Redeemable Second Preferred Shares Series I and M at prices of $25 per share plus accrued dividends.

On June 1, 1994, 1,795,230 of Cumulative Redeemable Second Preferred Shares Series L were retracted at a price of $25 per share plus accrued dividends.

On December 1, 1994, the Corporation issued $50.0 million of Cumulative Redeemable Second Preferred Shares Series S for cash.

The dividends payable on the Cumulative Redeemable Second Preferred Shares Series O are fixed until May 1, 1996. Thereafter, the dividend rate may be established by negotiation between the Corporation and the holders of the shares.

Redemption and retraction privileges

The preferred shares of the Corporation are redeemable subject to premiums listed plus accrued and unpaid dividends. The Cumulative Redeemable Preferred Shares and the non-retractable Cumulative Redeemable Second Preferred Shares Series C and L are redeemable at the option of the Corporation at any time. The remaining Cumulative Redeemable Second Preferred Shares will be subject to redemption at the option of the Corporation commencing on the dates specified below.

The retractable Cumulative Redeemable Second Preferred Shares are retractable on the dates specified below at the option of the holder at the stated value plus accrued and unpaid dividends.

	Stated Value	Redemption Date	1995 Redemption Premium	Retraction Date
	(dollars)			
Cumulative Redeemable Preferred Shares				
5%	$100	open	4%	none
4¼% Series	$100	open	2½%	none
6% Series	$100	open	1%	none
Cumulative Redeemable Second Preferred Shares				
Non-retractable				
7.30% Series C	$ 25	open	nil	none
7.70% Series L	$ 25	open	nil	none
7.875% Series O	$ 25	May 2, 1996	n/a	none
Retractable				
7.10% Series N	$ 25	June 1, 1995	nil	June 1, 1995
8.00% Series P	$ 25	December 2, 1996	n/a	December 2, 1996
5.90% Series Q	$ 25	December 1, 1998	n/a	December 1, 1998
5.30% Series R	$ 25	June 1, 1999	n/a	June 1, 1999
6.60% Series S	$ 25	March 1, 2000	n/a	March 1, 2000

Purchase obligations

The Corporation is required in each year to make all reasonable efforts to purchase for cancellation the Cumulative Redeemable Second Preferred Shares listed below at a price not exceeding $25 per share plus costs of purchase. If the Corporation is unable to do so, the obligation to purchase shares in that year is extinguished.

	1994 Share Purchase Obligations	**Purchased in 1994** Shares	**Purchased in 1994** Amount
Series C	36,000	**3,600**	**$0.1**
Series L	12,095	**200**	
			$0.1

The aggregate of purchase obligations and maximum possible retractions of preferred shares for each of the next five years is:

1995	1996	1997	1998	1999
$101.5	$126.5	$1.5	$126.5	$151.5

7. Class A and Class B shareholders' equity

	1994	1993	Dividends **1994**	Dividends 1993
Class A non-voting shares	**$ 340.6**	$339.8	**$55.5**	$54.6
Class B common shares	**143.5**	144.1	**34.0**	33.6
Retained earnings	**548.2**	499.5		
	$1,032.3	$983.4	**$89.5**	$88.2

7. **Class A and Class B shareholders' equity** (continued)

Class A and Class B shares

Authorized:

An unlimited number of Class A non-voting shares and Class B common shares.

Issued:

	Class A non-voting		Class B common	
	Shares	Amount	Shares	Amount
Beginning of year	**38,498,402**	**$339.8**	**23,622,553**	**$144.1**
Options exercised	**11,000**	**.2**		
Exchanged	**100,602**	**.6**	**(100,602)**	**(.6)**
End of year	**38,610,004**	**$340.6**	**23,521,951**	**$143.5**

Shareholder rights

The holders of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by the Corporation on either of such classes of shares as well as the remaining property of the Corporation upon dissolution. The holders of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of the Corporation, holders of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, holders of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of the Corporation if ATCO Ltd., the present controlling shareholder of the Corporation, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of the Corporation. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering. The complete text of the rights of exchange attached to the Class A non-voting shares is set out in a Certificate of Amendment dated September 10, 1982 issued to the Corporation.

Stock option plan

Under the Corporation's Stock Option Plan, certain key employees may purchase Class A non-voting shares at $16.29 or $19.04. These options expire on or before February 25, 1995 and February 17, 1997, respectively. The exercise of the outstanding options would not materially dilute earnings per Class A and Class B share. Changes in shares under option are summarized below:

	1994	1993
Options at beginning of year	**401,500**	431,500
Exercised	**(11,000)**	(30,000)
Options at end of year	**390,500**	401,500

Retained earnings

The debenture trust indenture places certain limitations on the Corporation which include restrictions on the payment of dividends on Class A and Class B shares. Consolidated retained earnings in the amount of $179.2 million are free from such restrictions.

8. Related party transactions

Entity	Relationship	Transaction	Recorded As	1994	1993
ATCO Ltd. and subsidiaries	Parent	Administration expenses and rent	Operation and maintenance	**$ 2.9**	$ 2.6
		Security services, aircraft, leasehold and other costs	Operation and maintenance	**(1.0)**	(.8)
		Purchase price adjustments on Northland Utilities Enterprises Ltd.	Interest expense	**.3**	.2
ATCOR Resources Ltd.	Jointly controlled investment	Transportation and storage of natural gas	Revenues	**8.4**	9.0
		Gas gathering and processing	Revenues	**.3**	.3
		Natural gas purchases	Natural gas supply	**7.5**	8.3
		Natural gas purchases — ethane plant	Operation and maintenance	**11.1**	.9
		Administration services	Operation and maintenance	**(.3)**	(.3)
Thames Power	Joint venture	Management and technical services	Revenues	**6.3**	4.5
Other	Joint venture	Contract labour	Operation and maintenance	**(1.2)**	(1.5)

Transactions in parentheses represent cost recoveries.

These transactions are in the normal course of business and are recorded at the exchange value.

9. Retirement benefits

	1994	1993
Pension costs:		
Expensed	**$ 8.6**	$ 8.3
Capitalized	**2.3**	2.5
	$ 10.9	$ 10.8
Corporate pension contributions:	**$ 16.7**	$ 16.5

The present value of the accrued pension benefits based on actuarial calculations and the net assets available to provide for pensions are as follows:

	1994	1993
Market related value of assets	**$708.9**	$655.8
Accrued pension benefits	**651.9**	588.3
Surplus	**$ 57.0**	$ 67.5
Other retirement benefits expense	**$ 1.2**	$ 1.1

10. Commitments and contingencies

Minimum operating lease payments, which extend over periods not exceeding 15 years, are $10.9 million, $10.0 million, $9.9 million, $9.9 million, and $9.9 million for the years 1995 to 1999, respectively.

Under the terms of the financing agreement for the Barking Power Project described in note 2, the Corporation is committed to advance £24.1 million ($52.9 million) to the project. At December 31, 1994, £16.4 million ($35.9 million) [1993 — £10.7 million ($20.7 million)] has been advanced.

The Corporation is party to disputes and lawsuits in the ordinary course of business. Management is confident that the ultimate liability or benefit arising from these matters will have no material impact on the consolidated financial statements.

11. Segmented information

The Corporation and its regulated utility subsidiaries operate in the following principal business segments:

Electric utility, which includes the generation, transmission and distribution of electric power; and

Natural gas utility, which includes the production, purchase, transmission, transportation and distribution of natural gas.

	1994	1993
Regulated electric utility		
Revenues	**$650.2**	$602.3
Inter-segment	**.1**	.2
	650.3	602.5
Fuel and purchased power	**115.1**	88.8
Other expenses	**169.6**	154.3
Depreciation and depletion	**89.7**	85.4
Income taxes	**82.2**	77.9
	456.6	406.4
Segment operating income	**193.7**	196.1
Regulated natural gas utility		
Revenues	**887.9**	772.1
Inter-segment	**2.0**	1.7
	889.9	773.8
Natural gas supply	**409.9**	328.3
Other expenses	**247.6**	235.6
Depreciation and depletion	**59.7**	53.7
Income taxes	**56.9**	47.2
	774.1	664.8
Segment operating income	**115.8**	109.0
Total segment operating income	**309.5**	305.1
Allowance for funds used	**4.0**	5.0
Joint venture and investment income	**17.9**	17.3
Interest and other income	**4.2**	4.5
Corporate operating income (expenses)	**3.8**	(1.8)
Income taxes	**(9.8)**	(6.2)
Earnings before financing charges	**$329.6**	$323.9

	1994	1993
Total assets		
Regulated electric utility	**$1,967.1**	$1,954.0
Regulated natural gas utility	**1,233.2**	1,185.3
Other	**186.8**	165.8
	$3,387.1	$3,305.1
Capital expenditures		
Regulated electric utility	**$ 98.8**	$ 109.1
Regulated natural gas utility	**114.9**	128.1
Other	**1.4**	22.1
	$ 215.1	$ 259.3

12. Financial statements

Certain of the 1993 figures have been reclassified to conform with the consolidated financial statement presentation adopted in 1994.

13. Subsequent events

Frontec Group

Effective January 1, 1995 the Corporation acquired from ATCO Ltd., that company's 50% interest in the Frontec Group and a property management operation for a total purchase price of approximately $35.7 million. Consideration for the purchase was the issue of 935,679 Class A non-voting and 599,756 Class B common shares of the Corporation valued using a 20 day weighted average share price immediately preceding the date of closing. This transaction increased the Corporation's ownership of the Frontec Group from 50% to 100%.

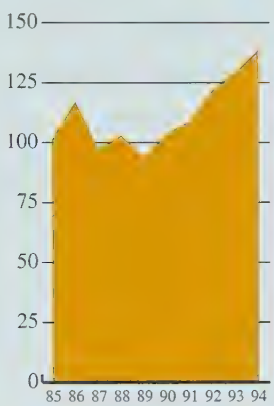
The purchase price was determined by valuations conducted by two independent valuators appointed by the Boards of Directors of the Corporation and ATCO Ltd.

Other

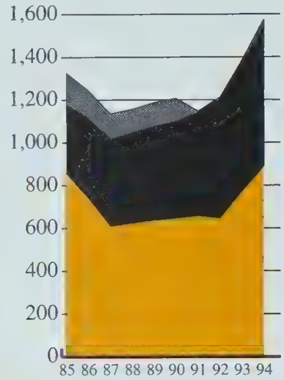
On January 26, 1995 the Corporation paid $80.0 million to acquire certain gas processing and pipeline assets from Norcen Energy Resources Limited.

CONSOLIDATED TEN-YEAR FINANCIAL SUMMARY

Earnings Attributable to Class A and Class B Shares
(millions of dollars)

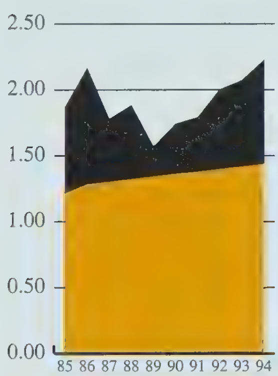


Revenues
(millions of dollars)



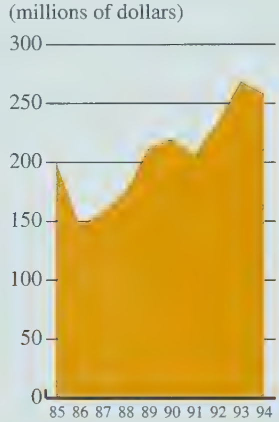
Natural Gas Utility
Electric Utility
Complementary

Earnings Per Class A and Class B Share
(dollars)

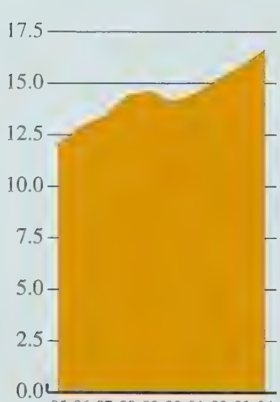


Dividends per share
Earnings retained per share

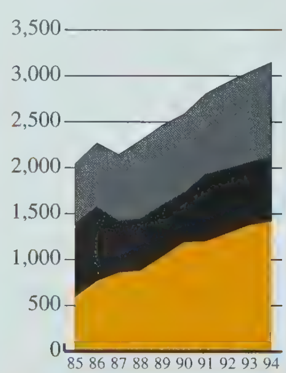
Cash Provided From Operations
(millions of dollars)



Equity Per Share
(dollars)



Capitalization
(millions of dollars)



Long-Term Debt
Preferred Shares
Shareholders' Equity

(Dollars in millions, except as indicated)		
EARNINGS		
Revenues	Natural gas utility	
	Electric utility	
	Non-utility oil and gas	
	Other	
Total Revenues		
Operating Expenses	Natural gas supply	
	Fuel and purchased power	
	Operation and maintenance	
	Depreciation and depletion	
	Franchise taxes	
	Property and other taxes	
	Income taxes	
Total Operating Expenses		
Operating Income		
Allowance for Funds Used		
Joint Venture Income		
Investment Income		
Interest and Other Income		
Earnings before Financing Charges		
Interest Expense		
Dividends on Preferred Shares		
Earnings Attributable to Class A and Class B Shares		
SEGMENTED EARNINGS		
Electric utility		
Natural gas utility		
Electric complementary		
Natural gas complementary		
Frontec		
ATCOR Resources		
Corporate		
CASH FLOWS		
Cash Provided from Operations		
Class A and B Dividends		
Financing		
Capital Expenditures		
CLASS A & B SHARES		
Shares Outstanding* (thousands)	At end of year	
	Average for year	
Return on Equity* (earnings attributable ÷ weighted average equity)		
Earnings per Share* ($) (earnings attributable ÷ weighted average shares)		
Dividends per Share* ($)		
Equity per Share* ($) (shareholders' equity ÷ end of year shares)		
Stock Market Record – Class A non-voting shares		High
		Low
		Close
		Daily Trading Volume
Stock Market Record – Class B common shares		High
		Low
		Close
		Daily Trading Volume
OTHER FINANCIAL INDICATORS		
Payout Ratio (dividends ÷ earnings attributable)		
Interest Coverage (pretax)		
BALANCE SHEET		
Property, Plant, and Equipment – Gross		
– Net of contributions		
Total Assets		
Capitalization		
Long-term debt and notes payable		
Preferred shares		
Shareholders' equity*		
Total Capitalization		
Capitalization Ratios – Year-end		
Long-term debt and notes payable		
Preferred shares		
Shareholders' equity*		

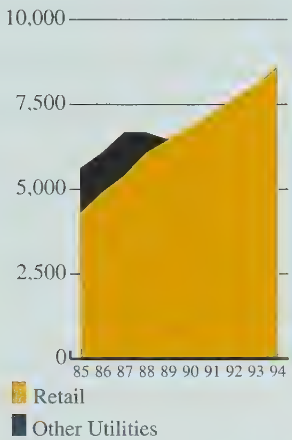
*Includes Class A non-voting shares and Class B common shares

1994	1993	1992	1991	1990	1989	1988	1987	1986	1985
887.9	772.1	645.9	656.0	646.0	636.3	622.9	607.5	737.0	854.1
650.2	602.3	557.1	483.9	452.5	439.5	424.1	408.6	375.2	324.0
				104.6	107.3	106.9	116.1	130.8	147.2
38.2	11.9	10.6	8.1	4.5	4.9	3.4	3.0	1.8	.6
1,576.3	1,386.3	1,213.6	1,148.0	1,207.6	1,188.0	1,157.3	1,135.2	1,244.8	1,325.9
409.9	328.3	240.6	272.2	291.6	294.5	284.1	299.9	395.9	479.3
115.1	88.8	87.6	75.9	65.5	61.2	65.6	67.2	67.3	60.4
344.7	312.2	307.8	288.1	332.6	337.6	312.7	304.6	317.2	316.5
155.7	139.8	121.4	105.6	113.2	125.5	102.1	86.7	81.7	96.6
70.3	61.1	50.2	50.4	49.9	48.4	44.4	43.8	51.7	56.9
28.2	27.7	25.9	23.6	21.1	18.9	17.4	15.7	16.0	41.5
148.9	131.3	109.7	82.2	97.6	90.8	106.9	121.1	121.9	105.4
1,272.8	1,089.2	943.2	898.0	971.5	976.9	933.2	939.0	1,051.7	1,156.6
303.5	297.1	270.4	250.0	236.1	211.1	224.1	196.2	193.1	169.3
4.0	5.0	23.2	36.2	32.6	27.8	20.5	26.1	34.6	46.9
18.1	15.0	13.0	3.2	1.5	.8	.4			
(.2)	2.3	3.4	1.4	(.3)	1.3	1.3	15.0	19.6	4.3
4.2	4.5	3.5	3.5	2.4	2.8	2.2	12.3	5.6	4.6
329.6	323.9	313.5	294.3	272.3	243.8	248.5	249.6	252.9	225.1
146.4	143.2	138.4	136.9	126.9	108.1	103.6	96.3	83.6	75.9
45.0	51.9	53.5	48.8	41.9	42.2	42.1	56.6	52.4	47.8
138.2	128.8	121.6	108.6	103.5	93.5	102.8	96.7	116.9	101.4
78.0	75.9	77.9	71.1	63.5	66.0	57.5	54.5	59.1	60.8
55.3	49.4	39.8	40.1	37.2	37.9	43.2	35.5	43.1	52.4
5.4	1.5	3.5	(.6)	(.6)	(.1)	.1			
1.3	(.4)	(1.0)	(1.4)	(1.6)	(.8)	(.1)			
5.4	6.3	3.6	1.2	.6	(.6)				
1.9	2.3	3.4	2.2	4.1	(9.2)	2.7	7.9	5.6	(16.1)
(9.1)	(6.2)	(5.6)	(4.0)	.3	.3	(.6)	(1.2)	9.1	4.3
138.2	128.8	121.6	108.6	103.5	93.5	102.8	96.7	116.9	101.4
257.6	267.6	232.5	205.6	218.8	210.8	173.9	156.8	145.3	198.7
89.5	88.2	85.2	83.9	81.2	80.0	71.9	70.8	69.7	66.1
46.5	54.4	83.8	186.2	182.8	144.3	118.2	(146.3)**	164.9	21.3
215.1	259.3	276.1	298.5	343.7	321.8	248.1	240.7	248.1	235.6
62,132	62,121	62,091	60,825	60,818	59,519	59,433	54,218	54,217	54,212
62,132	62,112	60,940	60,824	59,586	59,485	54,813	54,218	54,214	54,212
13.7%	13.4%	13.5%	12.5%	11.8%	10.9%	13.7%	13.6%	17.3%	16.0%
2.22	2.07	2.00	1.79	1.74	1.57	1.88	1.78	2.16	1.87
1.44	1.42	1.40	1.38	1.365	1.345	1.325	1.305	1.285	1.22
16.62	15.83	15.18	14.48	14.08	14.60	14.37	13.37	12.89	12.02
27	26⅞	23	21⅜	22	22⅜	20⅜	21⅝	20	19⅝
21⅞	20¼	18¾	18⅝	18¼	18¾	18	15	17⅝	16½
24	25⅝	20½	20¾	20⅜	21⅞	19⅝	19½	19	19¼
18,748	37,837	38,687	30,058	13,134	35,857	15,125	32,384	23,303	20,740
27⅜	26⅞	23	21¾	22	22⅜	20½	21¾	20⅛	19⅝
23⅛	20⅜	18¾	18⅝	18¼	18¾	18½	16	17⅞	16½
24⅛	25⅝	20¾	21⅜	20½	22	19½	19¼	19	19⅜
3,589	6,568	7,234	4,439	5,432	12,515	9,384	24,769	10,032	6,002
64.7%	68.5%	70.1%	77.3%	78.5%	85.5%	69.9%	73.2%	59.6%	65.2%
3.27	3.18	3.06	2.75	2.91	3.10	3.43	3.85	4.48	4.35
4,564.4	4,383.1	4,153.6	3,915.4	3,634.3	3,623.9	3,318.3	3,083.6	2,869.6	2,623.6
2,916.8	2,876.4	2,768.0	2,641.6	2,464.9	2,428.7	2,262.1	2,138.6	2,018.9	1,878.8
3,387.1	3,305.1	3,148.3	2,992.8	2,779.0	2,701.3	2,509.1	2,403.7	2,534.6	2,347.8
1,423.5	1,379.3	1,291.5	1,200.9	1,192.6	1,036.3	883.1	858.6	766.2	601.1
689.0	680.1	699.3	726.3	536.2	556.7	559.6	560.5	802.9	791.9
1,032.3	983.4	942.4	880.6	856.1	869.0	854.0	724.7	698.8	651.4
3,144.8	3,042.8	2,933.2	2,807.8	2,584.9	2,462.0	2,296.7	2,143.8	2,267.9	2,044.4
45%	45%	44%	43%	46%	42%	39%	40%	34%	29%
22%	23%	24%	26%	21%	23%	24%	26%	35%	39%
33%	32%	32%	31%	33%	35%	37%	34%	31%	32%

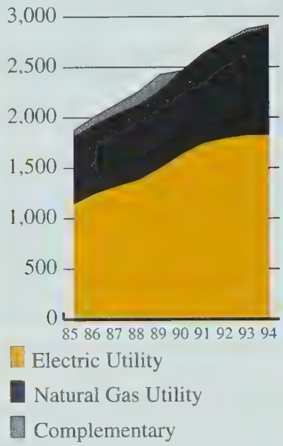
**Includes the redemption of $288.6 Series H Preferred Shares related to an investment in TransAlta Utilities. Financing would otherwise have been $142.3.

CONSOLIDATED TEN-YEAR OPERATING SUMMARY

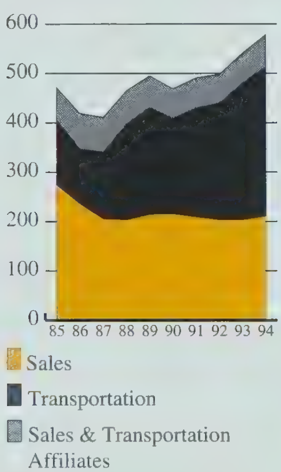
Electric Sales
(millions of kilowatt hours)



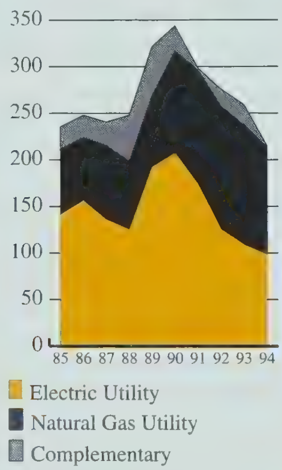
Property, Plant and Equipment (Net)
(millions of dollars)



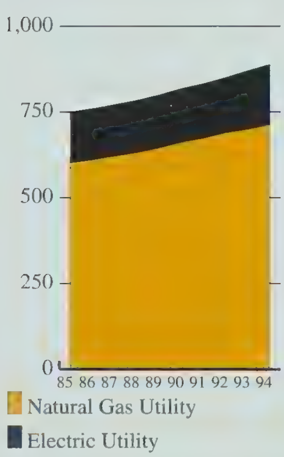
Natural Gas System Throughput
(petajoules)



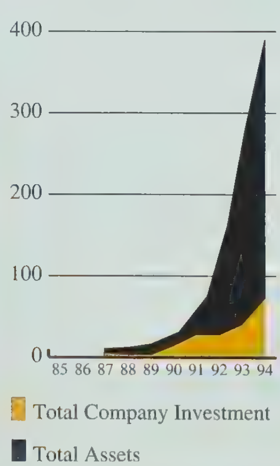
Capital Expenditures
(millions of dollars)



Gas and Electric Customers at Year-end
(thousands)



Joint Venture Operations
(millions of dollars)

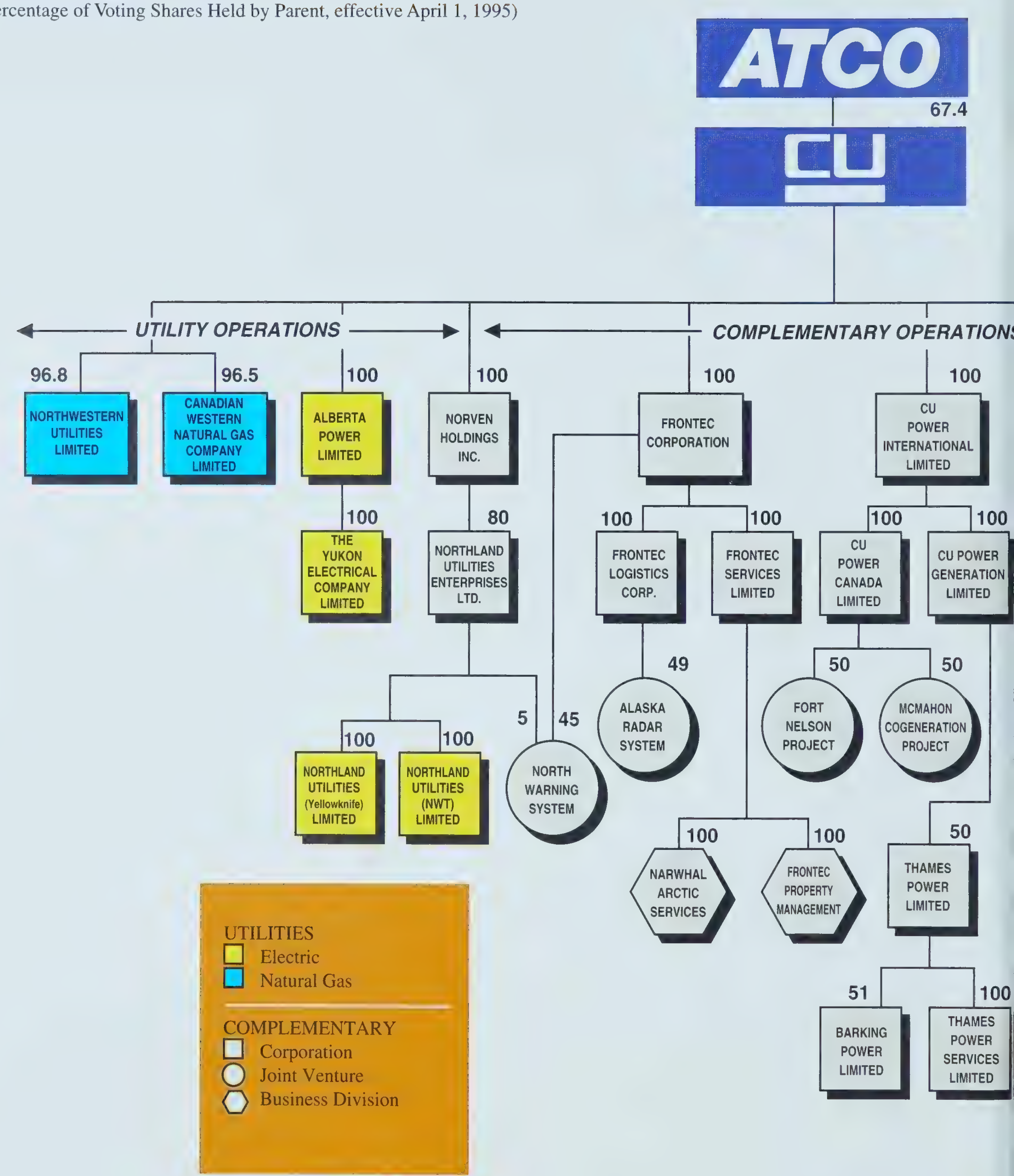


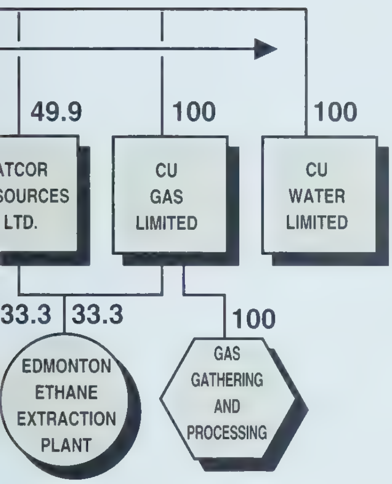
(Dollars in millions, except as indicated)
Electric Utility
Property, plant and equipment in service
Construction work in progress
Property, plant and equipment – gross
Accumulated depreciation
Unamortized contributions for extensions to plant
Property, plant and equipment – net
Growth over prior year
Capital expenditures
Sales (millions of kilowatt hours) – retail
– other utilities
Retail sales growth over prior years
Average annual use per residential customer (kWh)
Average annual billing per residential customer ($)
Maximum hourly demand (thousands of kilowatts)
Generating capacity (thousands of kilowatts)
Customers at year-end (thousands)
Number of communities served
Power lines (thousands of kilometres)
Natural Gas Utility
Property, plant and equipment – gross
Accumulated depreciation
Unamortized contributions for extensions to plant
Property, plant and equipment – net
Growth over prior year
Capital expenditures
Sales (petajoules)
Transportation (petajoules)
Sales and transportation – affiliates (petajoules)
Total system throughput (petajoules)
Growth over prior year
Average annual use per residential customer (gigajoules)
Average annual billing per residential customer ($)
Maximum daily demand (terajoules)
Degree days – Edmonton
– Calgary
Customers at year-end (thousands)
Number of communities served
Pipelines (thousands of kilometres)
Joint Venture Operations – CU Proportionate Share
Total assets
Property, plant and equipment – net
Total company investment
Revenues
Earnings
Total Number of Employees

1994	1993	1992	1991	1990	1989	1988	1987	1986	1985
2,733.8	2,647.6	2,524.3	2,415.6	2,244.4	1,827.5	1,712.2	1,632.4	1,501.5	1,097.8
14.1	17.5	26.5	24.9	33.6	249.0	180.7	140.5	147.8	396.8
2,747.9	2,665.1	2,550.8	2,440.5	2,278.0	2,076.5	1,892.9	1,772.9	1,649.3	1,494.6
800.8	723.7	646.2	583.9	529.0	468.5	413.5	359.3	311.3	264.7
121.3	117.8	112.5	111.1	110.6	107.4	96.1	92.0	88.8	81.6
1,825.8	1,823.6	1,792.1	1,745.5	1,638.4	1,500.6	1,383.3	1,321.6	1,249.2	1,148.3
0%	2%	3%	7%	9%	8%	5%	6%	9%	9%
98.8	109.1	125.8	173.9	207.3	192.3	125.6	136.0	156.2	142.0
8,595	8,035	7,660	7,188	6,799	6,467	6,083	5,408	4,919	4,331
						588	1,266	1,166	1,290
7%	5%	7%	6%	5%	6%	12%	10%	14%	12%
7,573	7,522	7,352	7,742	7,689	7,577	7,360	7,188	7,336	7,432
789	768	691	675	608	556	582	525	565	660
1,313	1,292	1,284	1,183	1,235	1,135	1,055	979	895	844
1,439	1,436	1,427	1,425	1,424	1,232	1,235	1,237	1,252	1,058
174.0	171.1	160.9	159.0	157.0	154.6	152.5	150.5	149.8	147.1
359	358	349	348	347	347	347	347	351	348
51.3	50.0	49.0	48.4	47.9	46.8	45.5	44.0	41.7	39.1
1,773.1	1,670.8	1,577.8	1,468.9	1,352.5	1,255.0	1,184.7	1,119.6	1,054.6	990.7
529.2	481.4	447.3	414.1	372.9	341.5	305.0	273.2	248.0	221.3
186.5	175.8	172.7	162.8	155.6	147.3	138.8	128.6	119.7	108.4
1,057.4	1,013.6	957.8	892.0	824.0	766.2	740.9	717.8	686.9	661.0
4%	6%	7%	8%	8%	3%	3%	4%	4%	5%
114.9	128.1	131.2	122.3	109.2	76.4	73.0	79.3	68.0	69.0
211	203	203	209	215	214	203	205	235	274
302	277	237	221	194	217	194	136	112	131
65	61	58	61	60	64	68	70	72	66
578	541	498	491	469	495	465	411	419	471
7%	9%	1%	5%	(5%)	7%	13%	(2%)	(11%)	0%
154	152	149	154	161	161	148	139	155	176
695	620	514	524	535	532	497	480	558	621
2,335	2,292	2,482	2,308	2,388	2,524	2,062	1,799	2,120	2,291
5,332	4,995	4,946	4,918	5,163	5,271	4,696	4,407	4,923	5,414
5,030	5,049	4,778	4,790	4,968	5,173	4,493	4,073	4,620	5,124
713.5	698.5	688.9	673.0	661.1	644.5	631.3	620.9	610.1	601.8
290	290	294	294	294	294	294	293	292	292
37.6	37.0	36.9	36.3	35.3	34.8	34.4	33.9	33.5	32.8
384.1	274.9	133.8	47.7	23.5	13.2	8.8	5.5		
357.5	245.5	116.6	21.1	3.8	3.7	3.5	2.4		
73.0	40.7	27.6	27.9	14.7	3.3	3.5	4.5		
90.1	74.4	54.6	33.4	24.5	12.4	3.3	.2		
18.1	15.0	13.0	3.2	1.5	.8	.4			
4,286	4,370	4,440	4,509	4,365	4,341	4,175	4,114	4,048	3,991

CORPORATE STRUCTURE

(Percentage of Voting Shares Held by Parent, effective April 1, 1995)





DIRECTORS

W. L. Britton, Q.C.°+
Partner
Bennett Jones Verchere
Calgary, Alberta

B. K. French*
President
Karusel Management Ltd.
Calgary, Alberta

V. L. Horte°
President
V. L. Horte Ventures Inc.
Calgary, Alberta

W. R. Horton°*
Corporate Director
Sherwood Park, Alberta

H. E. Joudrie+
Chairman of the Board
Gulf Canada Resources Limited
Calgary, Alberta

R. W. A. Laidlaw+
Corporate Director
Calgary, Alberta

Rt. Hon. D. F. Mazankowski, P.C., D.Eng., L.L.D.°+
Corporate Director
Vegreville, Alberta

W. S. McGregor
President
W. S. McGregor Investments Ltd.
Edmonton, Alberta

H. M. Neldner*
Corporate Director
Sherwood Park, Alberta

C. S. Richardson°
Deputy Chairman of the Board
and Chief Financial Officer
Canadian Utilities Limited
Calgary, Alberta

D. M. Ritchie°
President
Medway Investments
Corporation Ltd.
Edmonton, Alberta

M. Sigler
President
Altius Corporation
Calgary, Alberta

N. C. Southern*
Chairman
Team Spruce Meadows Inc.
Calgary, Alberta

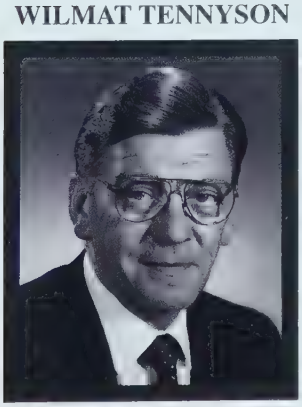
R. D. Southern, C.M., M.B.E., L.L.D.°
Chairman of the Board
and Chief Executive Officer
Canadian Utilities Limited
Calgary, Alberta

D. L. Tait, F.R.I., F.C.A.*
President
Tait Management Services Ltd.
Lethbridge, Alberta

Dr. J. D. Wood, F.C.A.E.°
President and Chief Executive Officer
Canadian Utilities Limited
Calgary, Alberta

° member of the Executive Committee
* member of the Audit Committee
+ member of the Human Resources Committee

In Memory
WILMAT TENNYSON



Mr. Wilmat Tennyson — a Director of ATCO Ltd., Canadian Utilities Limited, ATCOR Resources Ltd. and FRONTEC Logistics Corp. since 1990 — passed away on January 27, 1995 in Montreal, Quebec.

Highly respected in North American and European business circles, Wilmat was widely recognized for his marketing achievements. He was immensely proud of all that the ATCO Group has accomplished over the years, and his role as a Director greatly contributed to our successes.

Survived by his loving wife Helen, Wilmat made many friends throughout the group of companies — he will be sadly missed.

OFFICERS

R. D. Southern
Chairman of the Board and
Chief Executive Officer

C. S. Richardson
Deputy Chairman of the Board and
Chief Financial Officer

J. D. Wood
President and Chief Executive Officer

C. O. Twa
Executive Vice President

R. G. Lock
President
CU Gas Division

C. E. Barnicoat
Vice President,
Information Systems

J. A. Campbell
Vice President

D. T. Davis
Vice President and Controller

O. G. Edmondson
Treasurer

M. M. Shaw
Vice President

C. K. Sheard
Vice President,
Corporate Services and General Counsel

L. J. Vegh
Vice President,
Risk and Pension Fund Management

K. M. Watson
Vice President

S. R. Werth
Vice President, Administration

D. P. Wood
Corporate Secretary

D. R. Cawsey
Assistant Corporate Secretary

DIVISIONAL OFFICERS AND EXECUTIVES

J. R. Frey
President
Alberta Power Limited

G. K. Bauer
President
CU Power International Limited

G. W. Welsh
Chief Executive
Thames Power Services Limited

G. N. Paicu
President and Chief Executive Officer
Frontec Logistics Corp.

R. G. Lock
President
CU Gas Division

W. L. Graburn
Executive Vice President
CU Gas Division

D. M. Ellard
Senior Vice President and General Manager
Northwestern Utilities Limited

J. D. Graham
Senior Vice President and General Manager
Canadian Western Natural Gas Company Limited

Registered Head Office

10035 - 105 Street
Edmonton, Alberta T5J 2V6
Telephone (403) 420-7757
FAX (403) 420-7400

Incorporation

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

Annual Meeting

The annual meeting of shareholders will be held at 10:00 a.m., May 17, 1995 at The Westin Hotel, Edmonton, Alberta.

Auditors

Price Waterhouse
Edmonton, Alberta

Counsel

Bennett Jones Verchere
Edmonton, Alberta

Transfer Agent and Registrar

Class A non-voting and
Class B common shares
Preferred, Series Preferred
and Second Preferred
(Series C, L, N, P, Q, R and S) Shares

The R-M Trust Company
Montreal/Toronto/
Calgary/Vancouver

Duplicate Communication

Every effort is made to avoid duplication of information sent to our shareholders. Shareholders who receive duplicate mailings are requested to notify the Assistant Corporate Secretary at (403) 420-5467 or the Transfer Agent and Registrar, The R-M Trust Company, at 1-800-387-0825 (toll-free in Canada or the U.S.).

Trustee and Registrar

Debentures

National Trust Company
by its agent The R-M Trust Company
Montreal/Toronto/Winnipeg/
Calgary/Vancouver

Stock Exchange Listings

	Symbol	Listing
Class A non-voting	CU	Toronto Montreal Alberta
Class B common	CU.X	
Cumulative Redeemable Preferred Shares		
4¼% Series	CU.PR.A	Toronto
5%	CU.PR.B	
6% Series	CU.PR.C	
Cumulative Redeemable Second Preferred Shares		
7.30% Series C	CU.PR.G	Toronto Montreal
7.70% Series L	CU.PR.P	
7.10% Series N	CU.PR.R	
8.00% Series P	CU.PR.S	
5.90% Series Q	CU.PR.T	
5.30% Series R	CU.PR.V	
6.60% Series S	CU.PR.D	

ATCO Group Annual Reports

The annual reports to shareholders and management's discussion and analysis for Canadian Utilities Limited's parent company, ATCO Ltd., and CU's associated publicly traded operating company in the ATCO Group, ATCOR Resources Ltd., are available upon request from the corporate secretaries of those companies.

ATCO Ltd.
1600, 909 - 11th Avenue S.W.
Calgary, Alberta
T2R 1N6
Telephone: (403) 292-7546

ATCOR Resources Ltd.
600, 800 - 6th Avenue S.W.
Calgary, Alberta
T2P 3G3
Telephone: (403) 292-8160

CANADIAN UTILITIES LIMITED

An ATCO Company

Printed in Canada

AR36

CANADIAN UTILITIES LIMITED
An ATCO Company

Notice of Annual Meeting of Shareholders

May 17, 1995

NOTICE IS GIVEN that the Sixty-Eighth Annual Meeting of Shareholders of Canadian Utilities Limited will be held at The Westin Hotel, 10135 - 100 Street, Edmonton, Alberta on Wednesday, the 17th day of May, 1995 at the hour of 10:00 o'clock in the forenoon, Mountain Daylight Time, for the following purposes:

1. to receive and consider the annual report containing the consolidated financial statements for the year ended December 31, 1994, accompanied by the report of the auditor;

2. to elect directors;

3. to appoint the auditor;

4. to consider and, if deemed appropriate, pass a resolution approving certain amendments to the Stock Option Plan as described in the accompanying Management Proxy Circular; and

5. to transact such other business as may properly be brought before the Annual Meeting or an adjournment thereof.

DATED at Edmonton, Alberta this 17th day of March, 1995.

By Order of the Board,

D.P. Wood
Corporate Secretary

NOTE TO HOLDERS OF CLASS B COMMON SHARES:
If you are unable to attend the meeting kindly complete and sign the accompanying form of proxy and return it in the envelope provided to reach the Corporation at least 48 hours, excluding Saturdays and holidays, preceding the Annual Meeting or an adjournment thereof.

MANAGEMENT PROXY CIRCULAR

SOLICITATION OF PROXIES

This Management Proxy Circular is furnished in connection with the solicitation by the management of CANADIAN UTILITIES LIMITED (the "Corporation") of proxies to be used at the Annual Meeting of Shareholders of the Corporation to be held at the time and place and for the purposes set forth in the accompanying notice. It is expected that the solicitation will be primarily by mail. Proxies may also be solicited personally by officers and employees of the Corporation. The cost of the solicitation by management will be borne by the Corporation.

APPOINTMENT OF PROXYHOLDER AND REVOCATION OF PROXY

The persons named in the accompanying form of proxy are directors of the Corporation. A shareholder entitled to vote at the Annual Meeting may by means of a proxy appoint a proxyholder and one or more alternate proxyholders, who are not required to be shareholders, other than the persons designated in the accompanying form of proxy, to attend and act at the Annual Meeting in the manner and to the extent authorized by the proxy and with the authority conferred by the proxy. This right may be exercised either by striking out the names of the persons designated in the form of proxy and inserting in the space provided the name of the person appointed or by completing and executing another proper form of proxy. A shareholder desiring to be represented at the Annual Meeting by a proxyholder must deposit a proxy with the Corporation at least 48 hours, excluding Saturdays and holidays, preceding the Annual Meeting or an adjournment thereof.

A shareholder may revoke a proxy by depositing an instrument in writing executed by the shareholder or by the shareholder's attorney authorized in writing at the registered office of the Corporation, 1927, 10035 – 105 Street, Edmonton, Alberta T5J 2V6, at any time up to and including the last business day preceding the day of the Annual Meeting, or an adjournment thereof, at which the proxy is to be used, or with the chairman of the Annual Meeting on the day of the Annual Meeting or an adjournment thereof.

CLASS B COMMON SHARES AND PRINCIPAL HOLDERS THEREOF

There are outstanding 24,080,119 Class B common shares of the Corporation entitled to be voted at the Annual Meeting. Each Class B common share entitles the holder thereof to one vote. The directors have fixed April 5, 1995 as the record date for determining shareholders entitled to receive Notice of the Annual Meeting of Shareholders.

To the knowledge of the directors and officers of the Corporation, the only person who beneficially owns or exercises control or direction over shares of the Corporation carrying more than 10% of the votes attached to the shares of the Corporation is ATCO Ltd. (" ATCO"). ATCO directly or indirectly owns 16,238,308 Class B common shares, being approximately 67.4% of the Class B common shares outstanding. R.D. Southern controls ATCO. Reference is made to "Election of Directors".

CLASS A NON-VOTING SHARES

The holders of the Class A non-voting shares of the Corporation are entitled to receive Notice of the Annual Meeting of Shareholders and to attend and participate in discussions at the Annual Meeting, but are not entitled to vote at the Annual Meeting.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of the Corporation, holders of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, holders of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of the Corporation if ATCO, the present controlling shareholder of the Corporation, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of the Corporation. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or a rights offering. The complete text of the rights of exchange attached to the Class A non-voting shares is set out in a Certificate of Amendment dated September 10, 1982 issued to the Corporation.

VOTING OF PROXIES

All Class B common shares of the Corporation represented by a proxy in favour of the persons designated in the accompanying form of proxy will be voted or withheld from voting on any ballot that may be called for in accordance with the instructions of the shareholder contained in the proxy. Where no choice is specified by the shareholder in the proxy, the proxy will be voted in favour of the matters referred to therein.

The accompanying form of proxy confers discretionary authority in respect of amendments to matters identified in the Notice of Annual Meeting of Shareholders and in respect of other matters that may properly come before the Annual Meeting. The management of the Corporation is not aware of any amendments to the matters identified in the Notice of Annual Meeting of Shareholders nor of any other matters that are to be presented for action at the Annual Meeting.

ELECTION OF DIRECTORS

The management of the Corporation proposes to nominate, and the persons named in the accompanying form of proxy intend to vote for the election as directors of the Corporation, the persons whose names are set forth below, all of whom, with the exception of Messrs. Shaben and Sirkis, are now directors and have been for the periods indicated. Mr. Shaben is Vice Chairman of Petrovalve International Inc.; prior thereto he was President of Petrovalve International Inc. and prior thereto he was President of Shaben World Enterprises Inc. Mr. Sirkis is a partner of Bennett Jones Verchere. The management of the Corporation does not contemplate that any one of the nominees will be unable to serve as a director. Each director elected will hold office until the close of the next Annual Meeting of Shareholders of the Corporation. Following is information with respect to each proposed nominee for the Board of Directors.

Nominees for election as director and offices held with the Corporation	Positions and offices held with significant affiliates of the Corporation	Principal occupation	Periods served as a director	Number of shares of each class of shares of the Corporation and significant affiliates of the Corporation beneficially owned or controlled (4)
W.L. Britton, Q.C. (1) (3)	Director of Alberta Power Limited, ATCOR Resources Ltd., ATCO Structures Inc., CanUtilities Holdings Ltd. and ATCO	Partner, Bennett Jones Verchere (barristers and solicitors)	1980 to date	1,000 Class A non-voting shares of the Corporation; 2,500 Class A Non-Voting shares of ATCOR Resources Ltd.; 5,014 Class I non-voting and 3,935 Class II voting shares of ATCO
B.K. French (2)	Director of Alberta Power Limited, ATCOR Resources Ltd., ATCO Structures Inc. and ATCO	President, Karusel Management Ltd. (property management and management consultants)	1981 to date	350 Class B common shares of the Corporation; 5,088 Class B Common shares of ATCOR Resources Ltd.; 1,900 Class I non-voting and 3,900 Class II voting shares of ATCO

Nominees for election as director and offices held with the Corporation	Positions and offices held with significant affiliates of the Corporation	Principal occupation	Periods served as a director	Number of shares of each class of shares of the Corporation and significant affiliates of the Corporation beneficially owned or controlled (4)
V.L. Horte (1)	Director of ATCOR Resources Ltd.	President, V.L. Horte Ventures Inc. (private investment company)	1981 to date	1,100 Class A non-voting and 100 Class B common shares of the Corporation
W.R. Horton (1) (2)		Corporate Director	1984 to date	100 Class B common shares of the Corporation; 2,000 Class B Common shares of ATCOR Resources Ltd.; 100 Class II voting shares of ATCO
H.E. Joudrie (3)		Chairman of the Board, Gulf Canada Resources Limited (oil and gas exploration and production company)	1982 to date	2,000 Class A non-voting shares of the Corporation
R.W.A. Laidlaw (3)		Corporate Director	1981 to date	500 Class A non-voting shares and 100 Class B common shares of the Corporation; 1,000 Class A Non-Voting and 25 Class B Common shares of ATCOR Resources Ltd.
Rt. Hon. D.F. Mazankowski, P.C., D.Eng., L.L.D. (1) (3)		Business Consultant and Corporate Director	1994 to date	
H.M. Neldner (2)		Corporate Director	1991 to date	500 Class A non-voting shares of the Corporation
C.S. Richardson, Deputy Chairman of the Board and Chief Financial Officer (1)	Director of Alberta Power Limited, Canadian Western Natural Gas Company Limited, Northwestern Utilities Limited, ATCOR Resources Ltd. and ATCO Structures Inc., Vice President and Chief Financial Officer and director of CanUtilities Holdings Ltd., and Senior Vice President, Finance and Chief Financial Officer and director of ATCO	Deputy Chairman of the Board and Chief Financial Officer of the Corporation and Senior Vice President, Finance and Chief Financial Officer, ATCO (management company)	1980 to date	29,000 Class A non-voting, 1,000 Class B common, 3,800 Series Q and 2,000 Series R second preferred shares of the Corporation; 1,500 Class A Non-Voting and 250 Class B Common shares of ATCOR Resources Ltd.; 1,000 Cumulative Redeemable Preferred Shares, Series A of CanUtilities Holdings Ltd.; 3,544 Class I non-voting and 13,800 Class II voting shares of ATCO
L.R. Shaben	Director of Alberta Power Limited	Vice Chairman , Petrovalve International Inc. (valve manufacturing company)		
M. Sigler		President, Altius Corporation (financial and management consulting company)	1989 to date	300 Class B common shares of the Corporation; 300 Class A Non-Voting shares of ATCOR Resources Ltd.; 500 Class I non-voting and 325 Class II voting shares of ATCO
R.B. Sirkis		Partner, Bennett Jones Verchere (barristers and solicitors)		
N.C. Southern (2)	Director of Alberta Power Limited, ATCOR Resources Ltd., ATCO Structures Inc. and ATCO	Chairman, Team Spruce Meadows Inc. (management, marketing and television production company)	1990 to date	925 Class A non-voting and 1,070 Class B common shares of the Corporation; 232 Class A Non-Voting and 21,193 Class B Common shares of ATCOR Resources Ltd.; 1,400 Class I non-voting and 9,150 Class II voting shares of ATCO

Nominees for election as director and offices held with the Corporation	Positions and offices held with significant affiliates of the Corporation	Principal occupation	Periods served as a director	Number of shares of each class of shares of the Corporation and significant affiliates of the Corporation beneficially owned or controlled (4)
R.D. Southern, C.M., M.B.E., L.L.D., Chairman of the Board and Chief Executive Officer (1)	Director of Alberta Power Limited, Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited, Chairman of the Board, Chief Executive Officer and director of ATCO, ATCOR Resources Ltd. and ATCO Structures Inc., and Chairman of the Board, President and Chief Executive Officer and director of CanUtilities Holdings Ltd.	Chairman of the Board and Chief Executive Officer of the Corporation and ATCO	1977 to 1979 1980 to date	2 Class A non-voting, 72, 402 Class B common, 40,000 Series N and 20,000 Series Q second preferred shares of the Corporation; 1 Class A Non-Voting and 11,201 Class B Common shares of ATCOR Resources Ltd.; 80,000 Cumulative Redeemable Preferred Shares, Series A of CanUtilities Holdings Ltd.; 5,186,313 Class I non-voting and 2,862,880 Class II voting shares of ATCO (5)
D.L. Tait, F.R.I., F.C.A. (2)	Director of Canadian Western Natural Gas Company Limited	President, Tait Management Services Ltd. (consulting and accounting management service company)	1992 to date	1,000 Class A non-voting shares of the Corporation; 10,000 Class A Non-Voting shares of ATCOR Resources Ltd; 1,400 Class I non-voting shares of ATCO
Dr. J.D. Wood, F.C.A.E., President and Chief Executive Officer (1)	Chairman of the Board, Chief Executive Officer and director of Alberta Power Limited, Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited, Deputy Chairman of the Board and director of ATCOR Resources Ltd. and ATCO Structures Inc., and President and Chief Operating Officer and director of ATCO	President and Chief Executive Officer of the Corporation and President and Chief Operating Officer, ATCO	1981 to date	60,000 Class A non-voting shares of the Corporation; 2,500 Class A Non-Voting shares of ATCOR Resources Ltd.; 35 preferred shares 5½% Series of Canadian Western Natural Gas Company Limited; 1,000 Class II voting shares of ATCO

Notes:

(1) Member of the Executive Committee.

(2) Member of the Audit Committee.

(3) Member of the Human Resources Committee.

(4) The information as to shares beneficially owned or controlled, not being within the knowledge of the Corporation, has been furnished by the directors.

(5) R.D. Southern beneficially owns directly 1,000 Class II voting shares of ATCO and is the controlling shareholder of Sentgraf Enterprises Ltd. which owns directly 5,186,313 Class I non-voting shares and 2,861,880 Class II voting shares of ATCO. The stated shareholdings of R.D. Southern include these shares. R.D.Southern controls ATCO which is the beneficial owner of 100% of the equity shares of CanUtilities Holdings Ltd. which owns 14,178,552 Class A non-voting and 15,578,552 Class B common shares of the Corporation. ATCO owns directly 2,195,679 Class A non-voting and 659,756 Class B common shares of the Corporation. All of the remaining shares of the Corporation beneficially owned or controlled by R.D. Southern are held by Sentgraf Enterprises Ltd., except for 2 Class A non-voting and 2 Class B common shares.

DIRECTORS' AND OFFICERS' LIABILITY INSURANCE

The Corporation, ATCO and their affiliates have purchased insurance with an annual aggregate limit of $35,000,000 for such corporations and their directors and officers. The approximate amount of premium paid by the Corporation in the financial year ended December 31, 1994 in respect of directors of the Corporation as a group was $2,592 and in respect of the officers of the Corporation as a group was $1,595. No part of the premium was paid by any director or officer. The Corporation is responsible for the first $500,000 of any loss and there is no deductible in respect of claims against each director or officer.

EXECUTIVE COMPENSATION

Summary Compensation Table

The following table sets forth information concerning the total compensation during the last three fiscal years of the Corporation's Chief Executive Officers and its four other executive officers employed at December 31, 1994 who had the highest individual aggregate salary and bonuses during 1994. **This information reflects all compensation received by the named executive officers from the Corporation and its subsidiaries for their services as executive officers in all capacities. The amounts contributed to Annual Compensation by the Corporation's three major regulated utility subsidiaries are shown on page 7.**

		Annual Compensation		All Other
Name and Principal Position	Year ended December 31	Salary ($)	Bonus ($)	Compensation (1) ($)
R.D. Southern (2)	1994	607,575	303,787	11,000 (3)
Chairman of the Board and	1993	321,468	160,733	6,600 (3)
Chief Executive Officer	1992	321,468	160,733	
Dr. J.D. Wood	1994	283,500	141,750	12,700 (3)
President and	1993	400,000	308,800	261,200 (4)
Chief Executive Officer	1992	400,000	288,000	
C.O. Twa (5)	1994	300,000	150,000	4,400 (3)
Executive Vice President	1993	200,000	112,080	1,900 (3)
	1992	200,000	120,000	
C.S. Richardson	1994	214,205	107,102	8,300 (3)
Deputy Chairman of the Board and	1993	211,255	105,625	261,200 (4)
Chief Financial Officer	1992	211,255	105,625	
R.G. Lock	1994	186,000	93,000	2,800 (3)
President,	1993	186,000	104,160	2,000 (3)
CU Gas Division	1992	190,333	83,330	
A.E. Scott	1994	176,000	88,000	Nil
Vice President,	1993	176,000	95,110	Nil
Finance and Planning	1992	176,000	88,705	

Notes:

(1) In accordance with transitional provisions in applicable executive compensation disclosure rules, amounts of "All Other Compensation" have not been included for financial years ended prior to 1993.

(2) On January 1, 1994, R.D. Southern was appointed Chairman of the Board and co-Chief Executive Officer of the Corporation. Prior to that appointment, he was Chairman of the Board.

(3) Represents directors' meeting fees.

(4) Represents directors' meeting fees of $11,200 and $250,000 in respect of a long-term value enhancement bonus. In 1992, the Human Resources Committee approved the payment of long-term value enhancement bonuses of $1,000,000 to Dr. J.D. Wood and C.S. Richardson, respectively, in recognition of their extraordinary efforts towards developing the Canadian Utilities Group and enhancing value for the Corporation's shareholders and their years of service to the Corporation. To date, they have each received half of their bonus entitlement, with the balance payable at retirement or earlier at the Corporation's discretion.

(5) On January 1, 1994, C.O.Twa was appointed Executive Vice President of the Corporation. Prior to that appointment, he was President, CU Power Division.

(6) The value of perquisites and personal benefits received in 1994 by each executive officer named in the table above is less than the lesser of $50,000 and 10% of the total of annual salary and bonus.

The Annual Compensation disclosed in the Summary Compensation Table includes amounts paid by the Corporation's three major regulated utility subsidiaries. The Corporation is a holding company whose subsidiaries include multifaceted regulated and non-regulated electric, natural gas and water businesses in Canada and internationally. Certain officers have positions in and provide services to various companies in the Canadian Utilities Group. The amounts paid for sharing access to senior executives is a benefit to the Corporation's three major regulated utility subsidiaries. In 1994, these subsidiaries paid the amounts set out below.

	Alberta Power Limited ($)	Northwestern Utilities Limited ($)	Canadian Western Natural Gas Company Limited ($)
R.D. Southern	331,735	156,755	119,085
Dr. J.D. Wood	109,573	89,160	84,765
C.O.Twa	115,950	94,350	89,700
C.S. Richardson	116,955	55,265	41,985
R.G. Lock	0	132,525	132,525
A.E. Scott	72,070	34,055	25,870

Aggregated Option Exercises During 1994 and Year-End Option Values

Name	Securities Acquired on Exercise (#)	Aggregate Value Realized ($)	Unexercised Options at December 31, 1994 (#) Exercisable / Unexercisable	Value of Unexercised In-the-Money Options at December 31, 1994 ($) Exercisable / Unexercisable
R.D. Southern	Nil	Nil	200,000 / Nil	1,404,500 / Nil
Dr. J.D. Wood	Nil	Nil	75,000 / Nil	509,500 / Nil
C.O. Twa	Nil	Nil	12,500 / Nil	62,000 / Nil
C.S. Richardson	11,000	102,685	103,000 / Nil	725,380 / Nil
R.G. Lock	Nil	Nil	Nil / Nil	Nil / Nil
A.E. Scott	Nil	Nil	Nil / Nil	Nil / Nil

Retirement Arrangements

R.D. Southern, Dr. J.D. Wood , C.O. Twa, C.S. Richardson, R.G. Lock and A.E. Scott participate in a registered pension plan for employees of the Corporation. The following table sets forth the annual pensions payable at normal retirement age of 65 based on various levels of pensionable earnings and years of service.

PENSION PLAN TABLE

Remuneration	Years of Service				
($)	15	20	25	30	35
150,000	25,830	34,440	43,050	51,660	60,270
175,000	25,830	34,440	43,050	51,660	60,270
200,000	25,830	34,440	43,050	51,660	60,270
225,000	25,830	34,440	43,050	51,660	60,270
250,000	25,830	34,440	43,050	51,660	60,270
300,000	25,830	34,440	43,050	51,660	60,270
400,000	25,830	34,440	43,050	51,660	60,270
500,000	25,830	34,440	43,050	51,660	60,270
600,000	25,830	34,440	43,050	51,660	60,270
700,000	25,830	34,440	43,050	51,660	60,270

The remuneration covered by the plan is salary only. The pension calculation is based on 2% of the average salary of the last 5 years (maximum $1,722 per year) times the number of years of credited service up to a maximum of 35 years.

As at December 31, 1994, the years of credited service accrued for the registered pension plan for the executive officers named in the Summary Compensation Table were as follows: R.D. Southern - 10.75, Dr. J.D. Wood - 12.75, C.O. Twa - 35.67, C.S. Richardson - 10.75, R.G. Lock - 17.17, and A.E. Scott - 13.67. R.D. Southern and C. S. Richardson have each served as executive officers of the Corporation for 14.75 years.

C.O. Twa, who participated in the registered plan prior to the introduction of legislated maximums, has the option of selecting a supplemental arrangement which, when included with the pension payable under the registered plan, provides for a pension based on 1-3/4% of the average salary of the last 5 years (with no annual maximum) times the number of years of credited service up to a maximum of 35 years. The following table sets out the annual pension payable at normal retirement age of 65 on the basis of the registered plan and this supplemental arrangement:

Remuneration	**Years of Service**		
($)	**25**	**30**	**35**
100,000	43,750	52,500	61,250
150,000	65,625	78,750	91,875
200,000	87,500	105,000	122,500
250,000	109,375	131,250	153,125
300,000	131,250	157,500	183,750
350,000	153,125	183,750	214,375
400,000	175,000	210,000	245,000

The Corporation has employment agreements with each of R.D. Southern, Dr. J.D. Wood and C.S. Richardson pursuant to which it has undertaken to provide a pension to these officers. See "Employment Agreements".

Employment Agreements

The Corporation has employment agreements with R.D. Southern, Dr. J.D. Wood and C.S. Richardson which contain substantially identical terms with the exception of salaries. The amounts of salary and the value of benefits paid under these agreements have been included in the Summary Compensation Table above. Employment of the executive officers may be terminated by the Corporation on 24 months notice or payment in lieu of notice and by the executive officers on 90 days notice.

Under these agreements the Corporation has undertaken to provide each of the three officers a pension payable any time after age 55 in the amount of 50% of the executive officer's average annual salary during the consecutive 60 month period for which such average was the highest, increased by two percentage points for each year or partial year that the officer's age is greater than 55 at the time of retirement up to a maximum of 70% for retirement at age 65 or thereafter. The pension payable under these agreements will be reduced by the amount of pension payable pursuant to the Corporation's registered pension plan.

Each agreement provides for the payment of certain benefits upon the death or total disability of an officer prior to retirement or termination. The amounts of such benefits are based on the officer's salary and are determined in accordance with formulas which take into account amounts payable to the officers under the Corporation's group life insurance policies and disability income programs.

Composition of the Human Resources Committee

The Human Resources Committee of the Board of Directors is responsible for determining the compensation of executive officers. The members of the Human Resources Committee are W.L. Britton, H. E. Joudrie, R.W.A. Laidlaw and Rt. Hon. D.F. Mazankowski.

Report on Executive Compensation

The compensation programs of the Corporation and its subsidiaries are designed to reward performance and to be competitive with the compensation arrangements of other North American companies of similar size and scope of operations. Each executive officer position is evaluated to establish skill requirements and level of responsibility. This evaluation provides a basis for internal and external comparisons of positions. The Committee, on information from other corporations and published data, periodically retains independent compensation consultants to undertake market comparisons and provide advice on developing appropriate compensation programs. The Committee retained independent compensation consultants in 1993 and 1994.

Components of Compensation

Executive officer compensation is composed of (i) salary, which is generally fixed below the median of market comparison, (ii) bonus, which is variable and dependent upon the Corporation achieving prescribed earnings targets, and (iii) stock options and share appreciation rights.

Salary

Salary ranges are generally determined following a review of market data for similar positions in corporations of comparable size and scope of operations. Market data for other major investor-owned Canadian utilities is from time to time reviewed in determining compensation levels. The salary for each executive officer position is then determined having regard to the incumbent's responsibilities, individual performance factors, overall corporate performance, years of service, potential for advancement, performance reviews by immediate superiors, and the assessment of the Committee of such matters as presented by management. Generally, salaries for executive officers in the Corporation and its subsidiaries have not increased during the past three years (except where there have been changes in officers' responsibilities), notwithstanding strong profit and corporate performance. This has been a period of low inflation and, accordingly, the Committee has exercised restraint on increases.

R.D. Southern, Dr. J.D. Wood and C.S. Richardson also serve in similar senior executive positions with ATCO, the Corporation's parent. Salaries for these similar positions in ATCO and the Corporation are determined on a consolidated basis by the Compensation Committee of the Board of Directors of ATCO and the Committee. In 1994 the Corporation's share of the consolidated salary for each of these positions was 63% and is reflected in the Summary Compensation Table.

Bonus Plan

Executive officers participate in a management bonus plan which provides for the payment of annual bonuses which are dependent upon the achievement of prescribed earnings targets set at the beginning of each financial year. The amount of bonus earned by an executive officer for a financial year is based on a percentage of the officer's salary (up to 30% or 50%, depending on the officer's position) and the Corporation's consolidated earnings which must meet or exceed the prescribed targets. In 1994, C.O. Twa, R.G. Lock and A.E. Scott participated in this bonus plan which is administered by the Committee. In 1994, the Corporation exceeded its earnings targets.

R.D. Southern, Dr. J.D. Wood and C.S. Richardson participate in a management bonus plan of ATCO. The amount of bonus earned for a financial year is dependent upon the consolidated net earnings of ATCO achieved in such year. No bonus is payable if earnings are not increased over the previous year. The maximum bonus of up to 50% of salary is only payable if, as shown on the ATCO audited financial statements, net earnings, after tax and the payment of bonuses, increase by at least 10% (rounded) from the previous financial year. A portion of the bonuses paid to R.D. Southern, Dr. J.D. Wood and C.S. Richardson under this plan (approximately 63%) is funded by the Corporation and is reflected in the Summary Compensation Table.

Stock Option and Share Appreciation Rights Plans

On November 23, 1994, the Board of Directors approved certain amendments to the Corporation's stock option plan, including the reservation of 2,000,000 Class A non-voting shares for issuance in respect of options. The Committee, together with the Chairman of the Board, may designate directors, officers and key employees of the Corporation and its subsidiaries to be offered options to purchase Class A non-voting shares at an exercise price equal to the weighted average of the trading price of the shares on The Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

In addition to the stock option plan, the Corporation adopted a share appreciation rights plan on November 23, 1994 under which share appreciation rights (SARs) may be granted to directors, officers and key employees of the Corporation and its subsidiaries. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The holder is entitled on exercise to receive a cash payment from the Corporation equal to any increase in the market price of the Class A non-voting shares over the base value of the SARs exercised. The base value is equal to the weighted average of the trading price of the Class A non-voting shares on The Toronto Stock Exchange for the five trading days immediately preceding the date of grant.

Compensation of Chief Executive Officers

The compensation of the Chief Executive Officers is determined by the same procedures used to develop compensation arrangements for other executive officers. A significant portion of overall compensation is tied to corporate performance and is paid only in the event that net earnings, after tax and payment of any bonuses, exceed prescribed targets.

Submitted by:
W.L. Britton, Chairman
H.E. Joudrie
R.W.A. Laidlaw
Rt. Hon. D.F. Mazankowski

Performance Graph

The graph below compares the cumulative shareholder return over the last five years on the Class A non-voting shares and Class B common shares of the Corporation (assuming a $100 investment was made on December 31, 1989) with the cumulative total return of the TSE 300 Composite Index and the TSE Utilities Subindex, assuming reinvestment of dividends.

Five - Year Total Return on $100 Investment

	1989	1990	1991	1992	1993	1994
Class A non-voting	100	103	113	120	159	156
Class B common	100	105	115	120	157	155
TSE 300	100	85	95	94	125	124
TSE Utilities	100	95	121	116	143	145

Note:

(1) The cumulative shareholder return on the Class A non-voting and Class B common shares illustrated above includes the distribution by the Corporation to shareholders of shares of ATCOR Resources Ltd. effective November 23, 1990 on the basis of one ATCOR share for every four shares of the Corporation held and assumes the continued holding by shareholders of such ATCOR shares.

Compensation of Directors

Directors of the Corporation are paid annual retainer and meeting fees of $12,000 and $700, respectively. In addition, the chairman and members of the Audit Committee receive annual retainers of $10,000 and $5,000, respectively. An additional meeting fee of $500 is payable for attendance at more than five Audit Committee meetings annually. The chairmen of the Pension Committee and the Human Resources Committee are each paid an annual retainer of $3,000. From time to time the Board forms ad hoc committees to undertake special initiatives. The chairman and members of any such ad hoc committees receive per diem fees of $2,000 and $1,200, respectively, which fees aggregated $19,260 in 1994. Directors who are officers of the Corporation receive only the meeting fee for meetings of the Board of Directors.

The Corporation has a consulting arrangement with Rt. Hon. D.F. Mazankowski, a director of the Corporation. Mr. Mazankowski received $50,000 in 1994 pursuant to this arrangement.

APPOINTMENT OF AUDITOR

The persons named in the accompanying form of proxy intend to vote for the appointment of Price Waterhouse as the auditor of the Corporation to hold office until the next Annual Meeting of Shareholders of the Corporation. Price Waterhouse was first appointed in 1981.

STOCK OPTION PLAN

On November 23, 1994, the Board of Directors approved certain amendments to the Corporation's stock option plan pursuant to which options ("Options") to purchase Class A non-voting shares of the Corporation may be granted to directors, officers and key employees of the Corporation and its subsidiaries. The principal amendments were (i) to increase the number of Class A non-voting shares issuable pursuant to the exercise of Options to 2,000,000, and (ii) to permit the participation of directors in the plan. Shareholders will be asked to consider and, if deemed appropriate, pass a resolution at the Annual Meeting approving the amendments.

Under the terms of the plan, as amended (the "Stock Option Plan"), the Board of Directors is authorized to provide for the granting, exercise and method of exercise of Options, all on such terms (which may vary between Options) as it shall determine. The Board of Directors has delegated the administration and operation of the Stock Option Plan to the Chairman of the Board and the Human Resources Committee. The number of Class A non-voting shares that may be acquired under an Option is determined at the time the Option is granted. Options can be granted for a term of up to 10 years. The Option exercise price shall not be less than the weighted average of the trading price of the Class A non-voting shares on The Toronto Stock Exchange for the five trading days immediately preceding the date of the grant of the Option.

If any director, officer or key employee of the Corporation or its subsidiaries who is a participant under the Stock Option Plan ceases to be a director, officer or key employee of the Corporation or its subsidiaries (i) for any reason other than death, permanent disability or normal retirement, the Option of such person will terminate on the earlier of its original expiration date and the 90th day after employment has terminated; or (ii) by reason of death, permanent disability or normal retirement, the Option of such person will terminate on the earlier of its original expiration date and 12 months after the date of death, permanent disability or normal retirement.

On February 1, 1995, the Corporation granted Options to acquire an aggregate of 590,000 Class A non-voting shares under the Stock Option Plan, subject to approval of the plan amendments by shareholders at the Annual Meeting. The Options have an exercise price of $23.76, being the weighted average of the trading price of the Class A non-voting shares on The Toronto Stock Exchange for the five trading days immediately preceding the date of the grant.

The Toronto, Montreal and Alberta stock exchanges have approved the Stock Option Plan subject to confirmation of the plan amendments by a majority of the votes cast at the meeting by holders of the Class B common shares. At the Annual Meeting, the following resolution will be placed before the Class B common shareholders for approval:

> "BE IT RESOLVED THAT amendments to the Canadian Utilities Limited Stock Option Plan on the terms substantially as described in the Corporation's Management Proxy Circular dated March 17, 1995, are hereby ratified, approved and confirmed."

A shareholder desiring to review the full text of the Stock Option Plan may receive a copy by contacting the Corporate Secretary of the Corporation at 10035 - 105 Street, Edmonton, Alberta T5J 2V6.

ADDITIONAL INFORMATION

Additional information regarding the business of the Corporation is contained in the Corporation's Annual Information Form dated March 30, 1995. Additional financial information is provided in the Corporation's comparative consolidated financial statements and the Management's Discussion and Analysis of Financial Condition and Results of Operations for the financial year ended December 31, 1994, which are contained in the Corporation's 1994 Annual Report. Copies of these documents and additional copies of this Management Proxy Circular may be obtained upon request from the Corporate Secretary of the Corporation at 10035 – 105 Street, Edmonton, Alberta T5J 2V6, or by phoning (403) 420-5467.

GENERAL

The contents and the sending of this Management Proxy Circular have been approved by the directors of the Corporation.

DATED at Edmonton, Alberta this 17th day of March 1995.

D.P. Wood
Corporate Secretary